FORT GORDON BOILER/CHILLER

VOL I

NARRATIVE REPORT

MARCH 1991

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

ENERGY SURVEYS OF UNITED STATES ARMY RESERVE CENTERS AT FORT SAM HOUSTON, SAN ANTONIO, AUSTIN & HOUSTON, TEXAS

VOLUME 2
MARCH 1991

UNDER CONTRACT NO.
DACA 63-88-C-0093

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ENERGY AUDIT PRE-FINAL SUBMITTAL
FOR FORT GORDON, GEORGIA

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EXECUTIVE SUMMARY

This document constitutes the Pre-Final Submittal for Contract DACA21-84-C-0603, Energy Audits of Boiler/Chiller Plants, Ft. Gordon, Georgia.

The purpose of this report is to indicate the work accomplished to date, show samples of field data collected, illustrate the methods and justifications of the approaches taken, outline the present conditions, and make recommendations for the potential energy efficiency improvements to the central heating and cooling plants of Fort Gordon. The specific buildings analyzed are:

Building 25910	Central Heating & Cooling Plant No. 1 (Chillers)
Building 25330	Central Heating & Cooling Plant No. 2 (Boilers & Chillers)
Building 310	Eisenhower Hospital Heating and Cooling Plant (Boilers)

Work Performed

This project as specified in Army Contract Number DACA21-84-C-0603 is composed of the following steps:

1. Determine the efficiency of the boiler/chiller plants by appropriate tests.

2. Survey the installation to determine if efficiency can be improved by the repair, addition or modification of equipment and recommend improvements.

3. Evaluate the controls systems and recommend changes, repairs or new controls which will improve the efficiency of the plants.

4. Review operation and maintenance procedures and provide site specific recommendations which will increase the efficiency of the plants to the maximum levels.

5. Prepare a comprehensive report to document the work performed, the results and recommendations. This report is to include Project Submission Documentation and supporting documentation for feasible Energy Conservation Opportunities (ECO's).

To date, the initial and detailed field work has been completed; the existing systems in the individual buildings have been reviewed and analyzed; the calculations on various ECO's have been completed and those not eligible for ECIP funding have either been disqualified or placed under the QRIP. Preliminary project documentation has been completed.

It is important to note that detailed equipment loading information is either not available or not reliable. An estimated load profile has been developed for chiller analysis based on ASHRAE load factor information and available weather data.

The analysis of the central energy plants concentrated on improving the efficiency of the individual boilers and chillers and the controls required to optimize the sequence of operation. The energy savings are calculated by various methods based upon such factors as overall improvements in component efficiency, improvements to control systems, or comparisons of different equipment types (e.g. electric centrifugal vs. steam absorption chillers). The study also addresses the operation and maintenance of the equipment in such areas as blowdown control; make-up water quantities; water treatment; preven~~ta~~tive maintenance practices; operator training; and equipment control, sequencing and monitoring. Additionally, though outside the scope of this contract, it has been identified that significant savings can be realized by making repairs to distribution systems.

Various measures have been identified which demonstrate~~s~~ potential energy savings. These projects include:

Building 25910 Projects

1. Variable Speed CHW Pumps

Building 25330 Projects

1. Portable O_2 Analyzer
2. Variable Speed HTW Pumps
3. Variable Speed CHW Pumps
4. Use of Heavy Oil
5. Variable Speed Forced Draft Blowers

Building 310 Projects

1. Variable Speed CHW Pumps
2. Variable Speed I.D. and F.D. Fans

Note that these projects do not qualify for ECIP funding, but all have demonstrated the potential for significant energy savings and all are recommended for implementation. Appropriate project documentation is included for those projects with savings to investment ratios greater than 1.0.

In addition, various O&M actions have been identified which offer substantial energy savings potential; some with only a minimal investment. In fact, in several instances the O&M requirements are of much greater importance, and would offer more significant savings than the QRIP project identified.

1.0 EXISTING INSTALLATION EQUIPMENT

Fort Gordon, Georgia is a tri-service signal and communications school with approximately 1600 buildings of which approximately 120 are served through boiler and chiller plants by Building Number 25910 (Plant No. 1) and Building Number 25330 (Plant No. 2).

The following sections of this report will describe each of Fort Gordon's boiler and chiller plants' existing equipment installations.

1.1 Boilers

Evaluation of Fort Gordon's existing boiler installations included efficiency testing for two identical Nebraska steam boilers for Building 25330 and three International Watertube boilers for Building 310. Originally, Building 25910's five A-type watertube boilers were part of the Scope of Work, but were deleted because of asbestos insulation on the steam lines. Specific descriptions for the installation equipment at each building are contained in the following sections of this report.

1.1.1 Building 25910

This building contains five essentially identical A-type watertube saturated steam generating boilers manufactured by Erie City. Units 1-3 are rated at 35,850 pounds per hour (PPH) and units 4-5 are rated at 34,000 PPH. All units are equipped with a multiple fuel burners capable of utilizing natural gas, No. 2 fuel oil or No. 6 fuel oil. In practice, the fuel of choice is natural gas with No. 2 fuel oil being used when under gas curtailment.

The boilers supply steam to three cascade-type water heaters mounted in the penthouse. The five boilers are equipped with a single economizer. The economizer is bypassed when burning oil and when the boiler load is very low.

The plant has common systems for:

- HTW pumping
- Boiler feedwater deaeration (inoperative October 1990)
- Boiler feedwater makeup
- Boiler feedwater pumps and piping
- Boiler controls
- Steam header connection
- Natural gas piping supply
- Fuel oil supply

The HTW is circulated throughout the three service zones by three horizontal, split-case, double-suction pumps of 50 HP, each with an identical standby unit. Each pump is powered by a two-speed electric motor which is normally operated at low speed. However, they may be manually switched to high speed when additional capacity is required.

Prior to testing of the boilers at Building 25910, evidence of asbestos insulation was discovered on the steam lines in which test instrumentation had to be installed. After unsuccessful attempts to remove the insulation, testing of the boilers in Building 310 was performed in lieu of those in Building 25910.

A specific description of the individual boilers that were to be tested in the test plan is as follows:

1. Number of Boilers: 5, essentially identical. Not tested.
2. Output: Saturated steam
3. Rated Capacity, each:
   a. Nos. 1, 2 & 3: 35,850 PPH.
   b. Nos. 4 & 5: 34,000 PPH
4. Mfg: Erie City Iron Works
5. Year Built:
   a. Nos. 1, 2 & 3: 1965
   b. No. 4: 1967
   c. No. 5: 1968
6. Primary Fuel: Natural Gas, (interruptible)
7. Secondary Fuel: No. 6 Fuel Oil (used 3-4 days per year)
8. Feedwater Meters: None
9. Gas Meters: One Roots type meter common to 5 units plus individual orifice plate meters, except on No. 5.
10. Fuel Oil Meters: Individual Positive Displacement meters.
11. Heat Recovery: Economizer
12. Stacks: One common stack
13. Fans: F.D. and I.D.
14. Furnace: Balanced draft.
15. Observed Condition: Nos. 1, 2, 3 & 4 operational on April 1, 1987. No. 5 out of service for furnace rebuild and replacement of controls.

MAJOR EQUIPMENT

BOILERS		ERIE CITY SATURATED STEAM
1-3		35850 PPH
4,5		34000 PPH

CASCADE WATER HEATERS (3 EA)

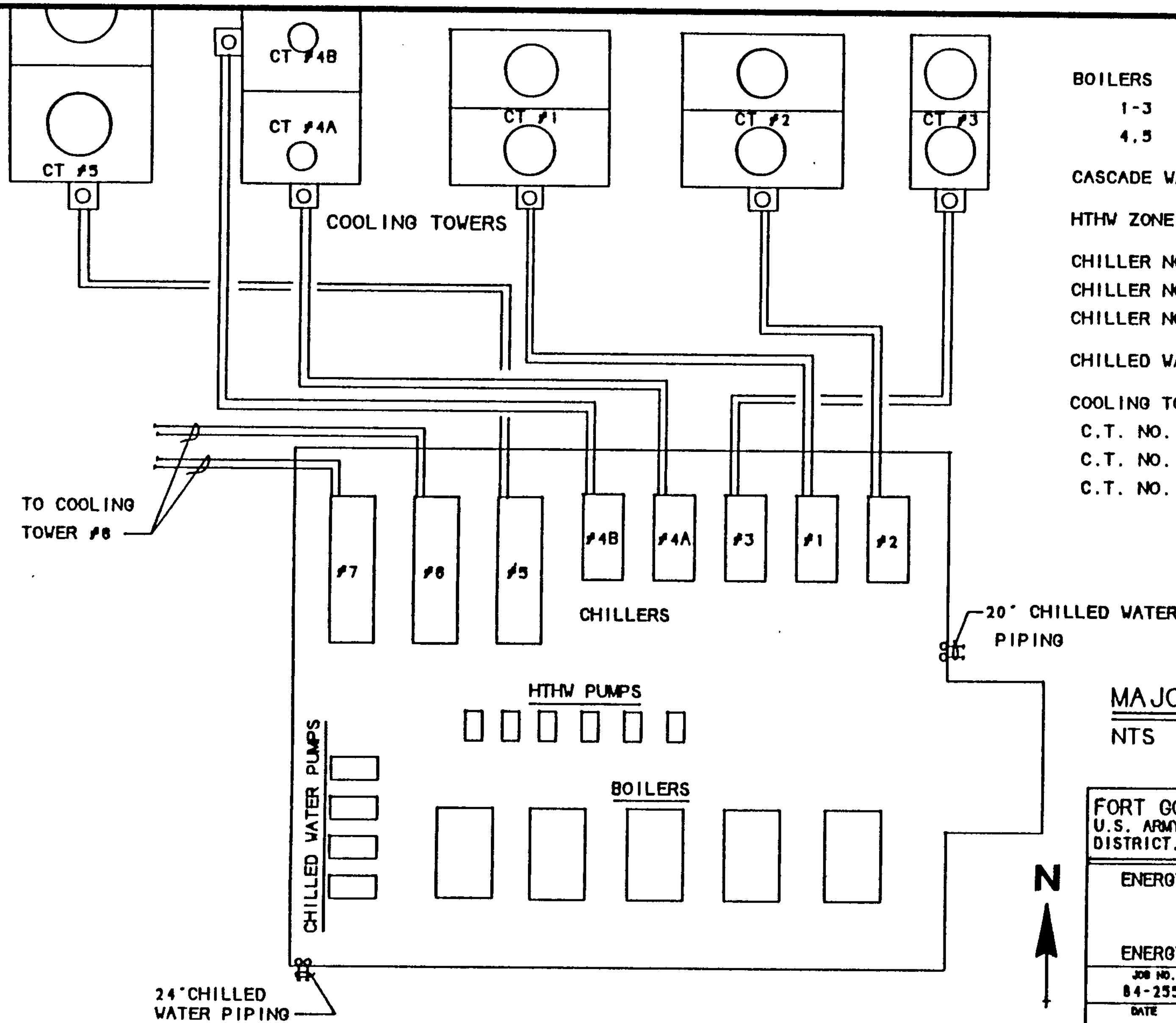
HTHW ZONE PUMPS (6) HORIZ. SPLIT CASE 50 HP

CHILLER NO.	1-3	CARRIER 700 TON
CHILLER NO.	4A,4B	CARRIER 750 TON
CHILLER NO.	5-7	YORK CODEPAK 700 TON

CHILLED WATER PUMPS (4) 300 HP VERT SPLIT CASE

COOLING TOWERS AND CW PUMPS

C.T. NO.	1-3	75 HP (EA) CW PUMPS
C.T. NO.	4A,4B	40 HP (EA) CW PUMPS
C.T. NO.	5,6	125 HP (EA) CW PUMPS



MAJOR EQUIPMENT PLAN

NTS

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING 25910

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255	GEE & JENSON	DWG. NO.
DATE	ENGINEERS-ARCHITECTS-PLANNERS, INC. 2000 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409	

1.1.2 Building 25330

This building contains two steam boilers with two cascade heaters, pumps, controls and accessories to provide central HTW.

The boilers are two D-type watertube steam generators, rated at 33,300 PPH each, piped opposite hand, and manufactured by Nebraska Boiler. Each unit is equipped with a multiple fuel burner capable of utilizing natural gas, No. 2 fuel oil or No. 6 fuel oil. The primary fuel is natural gas with No. 2 fuel oil being used when under gas curtailment.

The boilers supply steam to two cascade-type water heaters mounted in the penthouse to provide high temperature water (HTW). The boilers are manually sequenced and are fired as a primary/standby system with the boilers equally alternated. Both units have rectangular breaching led into a common free-standing steel stack.

The cascade heaters are Chicago Heater Co. deaeration units which directly inject steam into the returning system water to generate HTW as in Building 25910.

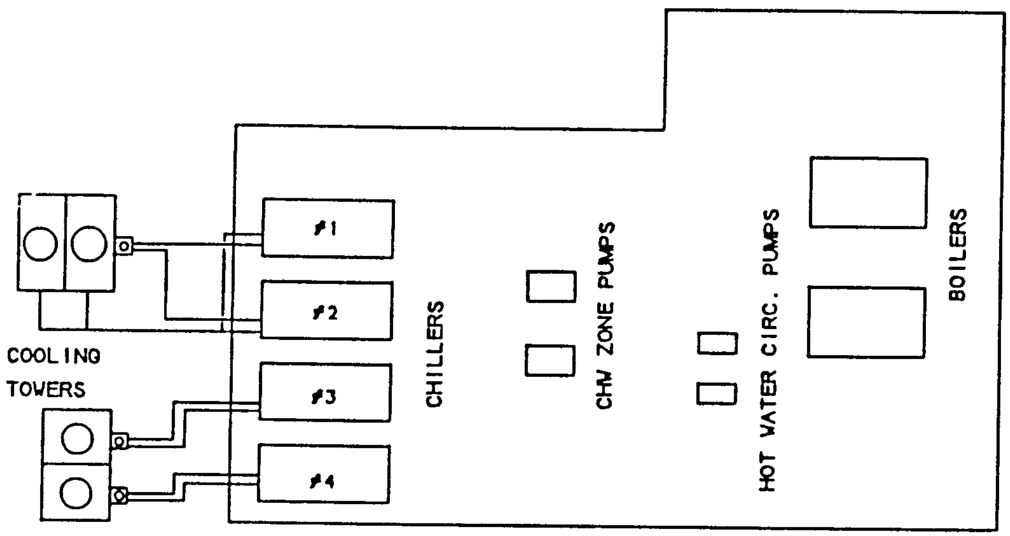
The HTW is circulated throughout the single-zone heating system by two 100 HP double-suction, vertical split-case pumps which are operated as a primary/stand-by pair. The pumps are operated alternately to provide equal wear.

The plant has common systems for:

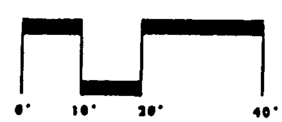
- Water softening
- HTW pumping
- Boiler feedwater deaeration
- Boiler feedwater makeup
- Boiler feedwater pumps and piping
- Boiler controls
- Steam header connection
- Natural gas piping supply
- Fuel oil supply

A specific description of the individual boilers to be tested in the test plan is as follows:

1. Number of Boilers: 2, essentially identical
2. Output: Saturated steam
3. Capacity, each: 33,000 PPH
4. Mfg: Nebraska Boiler
5. Year Built: 1975
6. Primary Fuel: Natural Gas (Approx. 95%)
7. Secondary Fuel: No. 2 Fuel Oil (Approx. 5%)
8. Feedwater Meters: Individual orifice plate meters.
9. Gas Meter: One Rockwell "Turbo-Meter" in gas line common to both units.
10. Fuel Oil Meters: Individual positive displacement meters.
11. Heat Recovery: None
12. Stacks: One, common to both units.
13. Furnace, Pressurized.
14. Fans: Forced draft only
15. Observed Condition: Both units operational
16. Estimated Maximum Flows:
    Gas Flow: (Max Predicted) 47,064 CFH
    Oil Flow: 284 GPH
    Water Flow: 3,960 GPH approx. 70 GPM



MAJOR EQUIPMENT PLAN



MAJOR EQUIPMENT

BOILER NO. 1 - NEBRASKA WATER TUBE. 33000 PPH
BOILER NO. 2 - NEBRASKA WATER TUBE. 33000 PPH

HTHW HEATERS - (2) CHICAGO HEATER CO. CASCADE TYPE

HTHW ZONE PUMPS - (2) 100 HP DOUBLE SUCTION VERTICAL SPLIT CASE (PRIMARY/SECONDARY)

CHILLER NO. 1 - CARRIER 19DM 500T
CHILLER NO. 2 - CARRIER 19DM 500T
CHILLER NO. 3 - TRANE CENTRAVAC 500T
CHILLER NO. 4 - TRANE CENTRAVAC 500T

COOLING TOWER NO. 1 - PRITCHARD TWO CELL INDUCTION WITH 40HP COOLING FANS AND SINGLE 125 HP COND. WATER CIRC. PUMP
COOLING TOWER NO. 2 - MARLEY DOUBLE FLOW WITH TWO 40 HP COND. WATER CIRC. PUMPS

CHILLED WATER ZONE PUMPS - TWO 350 HP DOUBLE SUCTION CENTRIFUGAL (PRIMARY/STANDBY)

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING 25330

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255	GEE & JENSON ENGINEERS-ARCHITECTS-PLANNERS, INC. 2000 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409	DWG. NO.
DATE		

1.1.3 Building 310

This building is the Eisenhower Hospital Steam Plant, which contains three identical International packaged watertube type boilers which operate at a balanced draft condition using both a forced draft (FD) and induced draft (ID) fans to control air flow. Each boiler has its own economizer and flue gas stack. The capacity of each is 16,400 PPH saturated steam.

This plant fires natural gas as its primary fuel for approximately 98% of the time and has No. 2 fuel as a secondary fuel.

The plant has common systems for:

- Water softening (inoperative October 1990)
- Condensate return storage
- Boiler feedwater deaeration
- Boiler feedwater makeup
- Boiler feedwater pumps and piping
- Boiler controls
- Steam header connection
- Natural gas piping supply
- Fuel oil supply

A specific description of the individual boilers to be tested in the test plan is as follows:

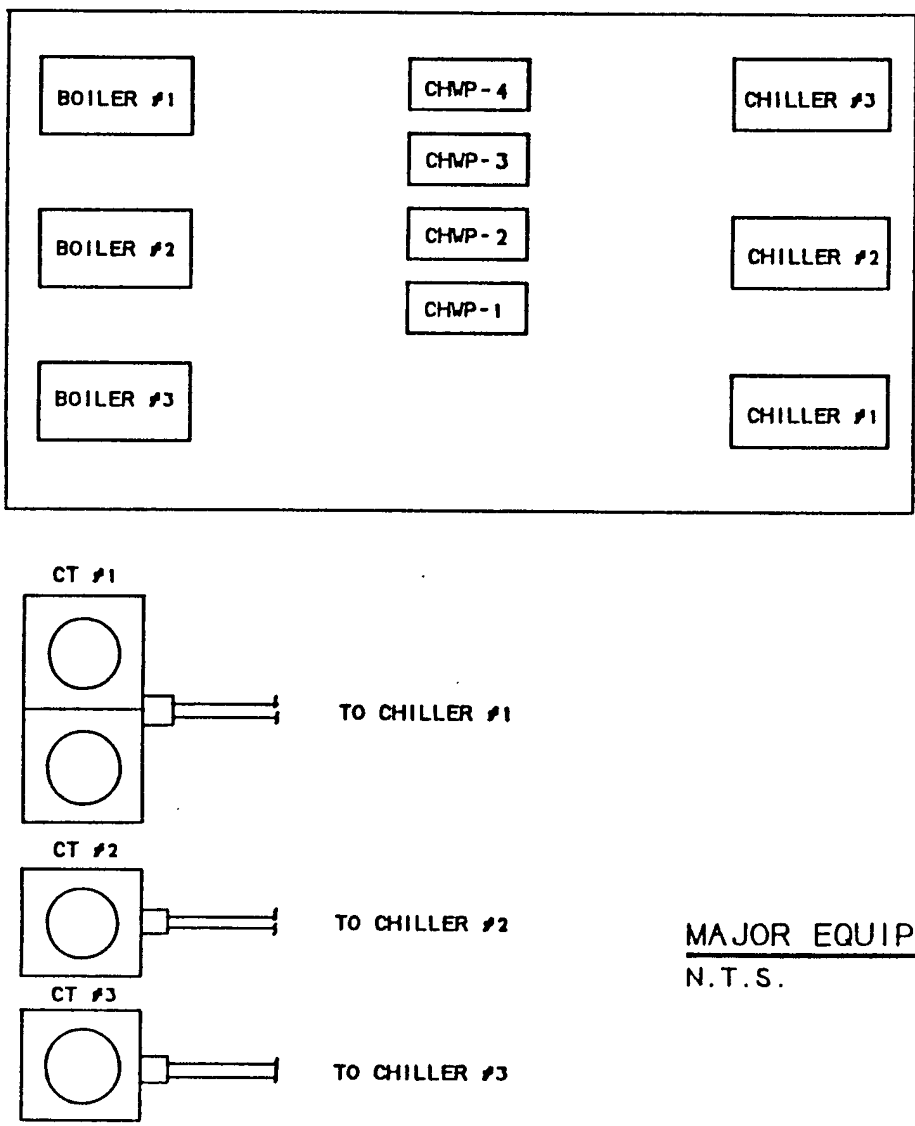
1. Number of Boilers: 3, essentially identical
2. Output: Saturated steam
3. Rated Capacity Each: 16,400 PPH
4. Mfg: International Watertube
5. Year Built: 1972
6. Primary Fuel: Natural Gas
7. Secondary Fuel: No 2 fuel oil (used 4-5 days per year)
8. Feedwater Meters: None
9. Gas Meter: One Rockwell "Turbo Meter" in gas line common to three units located outside the boiler house at the rear of the building.

10. Fuel Oil Meters: Individual Positive Displacement Meters
11. Heat Recovery: Cannon economizers installed on each unit
12. Stacks: Three individual
13. Fans: F.D. and I.D.
14. Furnace: Balance draft
15. Observed Condition: Operational
16. Estimated Maximum Flows:

    Gas Flow: 20,500 CFH

    Water Flow: 2304 GPH approx. 38.4 GPM

    Oil Flow: No. 2 oil, 110 lbs/hr with H.V. 18,500 BTUs/lb



MAJOR EQUIPMENT

BOILERS NO. 1-3 INTERNATIONAL WATER TUBE 18400 PPH

CHILLER NO. 1 - YORK CODEPAK 1050 TON
CHILLER NO. 2 - 470T STEAM TURB. CENTRIFUGAL
CHILLER NO. 3 - YORK CODEPAK 1050 TON

CHILLED WATER DISTRIBUTION PUMPS 1&2 - 100 HP
3 - 30 HP
4 - 20 HP

MAJOR EQUIPMENT PLAN

N.T.S.

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING 310

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255 DATE	GEE & JENSON ENGINEERS-ARCHITECTS-PLANNERS, INC. 2090 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409	DWG. NO.

1.2 Chillers

Evaluation of Fort Gordon's existing chiller installations included efficiency testing for four electrical centrifugal chillers located at building 25910 and two Carrier chillers at building 25330. More detailed descriptions of these installations are contained in the following sections of this report.

1.2.1 Building 25910

Chilled water service is supplied by three 700T Carrier electric centrifugal chillers, two 750T Carrier electric centrifugal chillers and three 700T York electric centrifugal chillers. Product data for these chillers are located in Volume 2, Section 3.2 of the Appendix. The three York chillers were not included in the "Scope of Work" and were not tested.

The individual chillers are manually cycled by the plant operator to meet the cooling demand. The three Carrier 700T chillers (Chillers 1-3) are each served by an individual dual-cell cooling tower with a 75 HP condenser water circulating pump and dual fans under separate control. The two Carrier 750T chillers (Chillers 4A and 4B) are each served by one cell of the same dual-cell cooling tower, and each has a 40 HP condenser water pump. The three 700T York chillers (Chillers 5-7) are served by two dual-cell cooling towers, each cooling tower having one 125 HP condenser water pump. These two towers are connected by a sump equalizing line and must always be operated as a pair. The cooling tower fans cycle automatically based upon the sump water temperature.

The chilled water is circulated throughout the two service zones by four 300 HP double-suction, vertical split-case centrifugal pumps, two per zone. These pumps are parallel piped and are generally operated as a primary/standby system. However, under peak cooling periods, the standby pump is also operated, as necessary, to supply the additional volume required.

A specific description of the individual chillers to be tested in the test plan is as follows:

1. Number of Chillers: 4 tested; 1 inoperative, 3 not in scope
2. Output: Chilled water
3. Capacity, each: 2 @ 700 tons; 2 @ 775 tons
4. Mfg: Carrier
5. Refrigerant: R-500, R-12
6. Flow meter: EMCO turbine flow meter
7. Computer: EMCO FP-100
8. Watt Meter: Dranetz #808
9. Thermometers: Fisher Scientific #15000B
10. Observed condition: Four of five chillers operational on August 31, 1987. All chillers operational in October 1990.

1.2.2 Building 25330

Chilled water service for this building is supplied by two Carrier 500T electric centrifugal chillers and two Trane 500T electric centrifugal chillers. Product data for these chillers are located in Volume 2, Section 4.1.2 of the Appendix. The two Trane 500T chillers and their associated cooling tower had not been installed at the time the chiller testing was conducted and were not included in the Scope of Work.

The two Carrier 500T chillers (Chillers 1 and 2) are served by a dual-cell cooling tower with a single 125 HP condenser water pump. The two Trane 500T chillers (Chillers 3 and 4) are each served by a single-cell of a dual-cell cooling tower. The condenser water for these chillers is circulated by two 40 HP pumps; one pump for each cell. The condenser water pumps are energized concurrent with the chillers, and the cooling tower fans cycle in response to sump water temperature.

The chilled water is circulated throughout the one service zone by two 350 HP, double-suction centrifugal pumps. These pumps are piped in parallel and are operated as a primary/standby pair with the pumps alternated to provide equal wear. The individual chillers are brought on line manually by the operators based on the chilled water temperatures.

A specific description of the individual chillers to be tested in the test plan is as follows:

1. Number of Chillers: 2 tested, 2 not in scope
2. Output: Chilled water
3. Capacity, each: 500 tons
4. Mfg: Carrier
5. Refrigerant: R-11
6. Flow meter: EMCO turbine flow meter

7. Computer: EMCO FP-100
8. Watt meter: Dranetz #808
9. Thermometer: Fisher Scientific #15000B
10. Observed condition: Both units operational on September 1, 1987.

2.0 PERFORMANCE TESTING

2.1 Boilers

Performance testing for existing boiler installations and procedures for operating and maintenance of boilers for Fort Gordon were conducted. The field tests were designed to determine the efficiency of the boilers while in operation, noting any changes made to equipment or controls during the tests. Testing results were recorded on the ASME abbreviated test code input/output test form as directed in the Scope of Work. The following discussion of the work performed for the boilers at Fort Gordon will include Buildings 25330 and 310.

The purpose of this compilation is to present the results of the boiler efficiency tests performed on each boiler as scheduled in the boiler test plan of October 1987.

This report fulfills the requirements of specification scope of work for Fort Gordon, Section 1.1 and 3.1 with respect to the actual testing and reporting of results and calculations. Analysis of these results, recommendations, and other supporting efforts are included in section 4.0 of this report.

Each boiler was tested in as normal an operating mode as possible with no changes to controls or operations other than putting the firing control in manual in order to hold a fixed firing rate for the duration of the test.

The test procedure used was in accordance with the ASME PTC 4.1 abbreviated form. The required data have been collected and the necessary calculations have been completed to show the boiler efficiency by both the input/output method, and by the heat loss method.

This report shows the specific boiler efficiency tests completed, their raw field data, and the resulting calculations required to complete the ASME PTC 4.1a summary sheet for abbreviated efficiency test. A graph which plots the resulting efficiency has been included for each boiler (Volume 2, Section 3.0).

The specific tests which were performed on the boilers are as follows:

1. Boiler efficiency by the input-output method, following the guidelines of the ASME PTC 4.1 methods.
2. Steam quality determination using a throttling calorimeter, on those boilers which are steam generators.
3. Boiler flue gas analysis tests performed with an orsat type analyzer.
4. Flue gas temperature documentation using a certified thermometer.
5. Boiler firing capacity test of short duration to determine the maximum firing rate the boiler is normally capable of.
6. Boiler feedwater system upset and response or recovery performance.
7. Boiler automatic controls upset and response or recovery performance.
8. Boiler ignition sequence and flame safeguard operation.

The following instruments were used on all boiler tests where their range and application match as listed.

APPLICATION	DEVICE	RANGE	ACCURACY
Steam Pressure	WIKA 312.20 Test Gauge	0-300 PSIG	±1/4%,±3/4psig
Steam Quality	Croll-Reynolds Company Throttling Calorimeter	0-5% Moisture	± 0.08% Moisture
Air Heater	Hays Orsat	O_2,CO_2,CO	± 3%
Flue Gas Analy.	Hays Orsat	O_2,CO_2,CO	± 3%
Flue Gas Temp.	Weksler AA5 Q-9	150-750°F	±5°F, 7/10%
Feedwater Press.	WIKA 312.20 Test Gauge	0-500 psig	±1/4%, ±1.25%
Feedwater Temp.	Weksler AA5H-9	30-300°F	±2°F, ±7/10%
Nat Gas Press.	WIKA 312.20 Test Gauge	0-30 psig	±1/4%,±0.075psig
Nat Gas Temp	Weksler A5H-9	0-120°F	±1 °F, ±8/10%
Oil Press.	WIKA 312.20 Test Gauge	0-300 psig	±1/4%, ±3/4psig
Oil Temp.	Weksler AA5H-9	30-300°F	±2°F, ±7/10%

The calculations for boiler efficiency are based on the input-output method as described in the ASME PTC 4.1. Heat loss method is also shown.

The boilers were tested at various firing rates, as stated in the schedules in this test plan, and the appropriate data were recorded for each time interval, at each rate, for each fuel required.

The following quantities were calculated:

Steam quality - where applicable
Actual water evaporated (Flow)
Total heat input
Fuel analysis
Fuel higher heat value
Efficiency of boiler in percent
Excess air after combustion
Flue gas analysis
Rate of fuel firing
Total heat input
Total heat output
Heat loss efficiency

The ASME Test Form for Abbreviated Efficiency Test Report was completed for each run on each fuel.

In addition to that data required to be collected to perform the boiler efficiency calculation as defined previously, data were collected to study those areas detailed in Section 2.1 of the Scope of Work.

Additionally, data were collected which allowed performance of the heat loss method of boiler efficiency to check the input/ output method calculations and to analyze the excess air percentage and boiler flue gas outlet temperature for possible recommendations.

Data were also collected during the testing of the boilers on:

1. Controls operation, in manual and auto
2. Flame Safety System Operation.
3. Burner operation
4. Boiler maximum capacity
5. Boiler minimum capacity
6. Boiler feedwater system operation
7. Boiler ignition system operation

All these and other data collected during a thorough study of the boiler plant operation were considered, analyzed, and summarized in Section 4.0 of this report.

2.1.1 Building 25330

The boiler test plan of October 1987 was adhered to as closely as possible. In Fort Gordon, Building 25330, boiler #1 was tested on natural gas and #2 oil, and boiler #2 was tested on natural gas. The testing was conducted from February 16th through February 19, 1988.

Boiler #1 was tested on February 16, 1988 at 25% capacity for two hours with natural gas with a 75.73% efficiency, at 50% capacity for two hours with natural gas for a result of 75.5% efficiency, and at 40% capacity for two hours with #2 fuel oil with an efficiency of 82.95%. On February 17, 1985, boiler #1 was tested with natural gas at 75% capacity with an efficiency of 74.65%. It was then tested at low fire on #2 oil with an efficiency of 79.86%, but it smoked badly. It was then tested at capacity for a short duration with #2 oil with an efficiency of 75.5%.

Boiler #2 was tested on February 18, 1985 at 40% capacity on natural gas, but testing had to be terminated early due to insufficient load. It was then tested again at 40% capacity in a forced fired condition. On February 19, 1988, it was force fired to 75% on natural gas with a 76.70% efficiency.

The specific boiler firing tests, firing rates and lengths of firing tests runs, and the fuels tested were as follows:

LOCATION	BUILDING	BOILER	POINTS %	DURATION	FUEL
Ft. Gordon	25330	1	25,50,75,100	2 HRS	GAS
Ft. Gordon	25330	1	40,75	2 HRS	OIL
Ft. Gordon	25330	2	40,75	2 HRS	GAS

DATA AND PLOT OF RESULTING CURVES

Following the testing of each boiler, on each fuel tested, the pertinent data were graphed against that boiler's firing H/A output. This will allow the review of the graphic trends on flow, efficiency, and excess air, as it relates to each boiler and fuel tested. The test data and graph are located in Appendix 3.2.3, Volume 2.

ESTIMATED ERROR FACTOR IN CALCULATIONS

LOCATION	BOILER	FUEL	MEASUREMENT ERROR (SUM)	ERROR IN CALCULATED EFFICIENCY
Ft. Gordon	1,2	Nat Gas	High Flow ±2.85%	± 2.7%
Building 25330	1	Oil	Low Flow ±3.6%	±3.45%
			High Flow ±2.85%	±2.7%
			Low Flow ±3.6%	±3.45%

It is important to note that the efficiencies calculated from the boiler test data may be unreliable due to the very low heat load conditions under which the data was obtained. Because of these low load conditions (i.e. relatively high outdoor temperatures), it was not possible to maintain a continuous firing rate at steady conditions for the full duration of the test. Consequently, it was not possible to stabilize the flow, temperatures and pressures prior to recording the data.

At some points in the testing, it was also necessary to operate equipment in the building or to change the feed rates in order to avoid having to drop the tested boiler from its assigned firing rate.

To attain capacity firing, it was necessary to drop the steam pressure by operating the boiler at the minimum firing rate for a short time after which the boiler was brought to maximum fire long enough to observe conditions and record data.

These methods are commonly employed in testing situations where sufficient load is not available to allow sustained firing at high rates. Though not as accurate as steady-state firing, they do provide reasonable approximations of steady-state, high-firing conditions.

It is generally accepted that, under these conditions, efficiencies calculated from the heat-loss method are somewhat more accurate than those obtained from the input/output method.

2.1.2 Building 310

The boiler test plan of October 1987 was adhered to as closely as possible. Boilers at Building 310 were tested instead of those in Building 25910 as approved by the Savannah District Corps of Engineers. This substitution was necessitated by the discovery of asbestos insulation on the steam lines in Building 25910.

Building 310, the Eisenhower Hospital Steam Plant, was tested from February 24th through February 26, 1988 and again from March 7th through March 10, 1988.

Boiler #1 was tested in February 24, 1988 at 25% capacity on natural gas. However, it was determined that the boiler was not set up at the proper fuel input rate, so it was retested at 25% capacity for two hours with natural gas with a 77.73% efficiency. It was then tested at capacity for a short duration with a 76.35% efficiency, but the testing was terminated early when the load dropped below 50%. A chiller was brought on line February 26th to provide sufficient load to test boiler #1 at 50% capacity for two hours with natural gas with an 81.24% efficiency. It was tested at 75% capacity for two hours with natural gas on the same day with an 81.52% efficiency. Boiler #1 was then tested on March 7, 1988 with #2 fuel oil at 40% capacity for two hours with an 85.57% efficiency. Boiler #1 was tested at 75% capacity on #2 oil with an 84.11% efficiency, but the test had to be terminated due to severe smoke problems.

Boiler #2 was tested on March 10, 1988 at 40% capacity for two hours with natural gas with an 81.25% efficiency and at 75% capacity for two hours on natural gas with an 80.50% efficiency. The testing was terminated after the boiler tripped on high pressure due to insufficient load. A capacity test was then run by force firing the boiler with a resultant 81.92% efficiency.

Testing was initiated on Boiler #3 on March 8, 1988 at 40% for two hours with natural gas with an 82.36% efficiency and at 75% capacity for two hours with natural gas with an efficiency of 82.51%. Testing was attempted on boiler #3 on March 9, 1988 with oil, but it stopped early due to severe smoke. It was then tested at capacity for one-half hour with natural gas for an 80.01% efficiency.

The specific boiler firing tests, both firing rates and lengths of firing tests runs, and the fuels tested are as follows:

LOCATION	BUILDING	BOILER	POINTS %	DURATION	FUEL
Ft. Gordon	310	1	25,50,75,100	2 HRS	GAS
Ft. Gordon	310	1	40,75	2 HRS	OIL
Ft. Gordon	310	2	40,75	2 HRS	GAS
Ft. Gordon	310	3	40,75	2 HRS	GAS
Ft. Gordon	310	3	100	½ HR	GAS

As was the case with the boiler tests in Building 25330, insufficient load existed during the testing period to maintain steady-state firing conditions at high firing rates for the full test duration. As a result, some tests were terminated early, and for some tests an artificial load was created to allow sustained operation at the assigned firing rate for the test. In some cases, it was necessary to terminate testing due to severe smoking. In those cases where sustained steady-state conditions could not be maintained, the accuracy of the test data could be adversely impacted.

DATA AND PLOT OF RESULTING CURVES

Following the testing of each boiler, on each fuel tested, the pertinent data were graphed against that boiler's firing H/A output. This will allow the review of the graphic trends on flow, efficiency, and excess air, as it relates to each boiler and fuel tested. The test data and graphs are located in Appendix 3.3.3, Volume 2.

ESTIMATED ERROR FACTOR IN CALCULATIONS

LOCATION	BOILER	FUEL	MEASUREMENT ERROR (SUM)	ERROR IN CALCULATED EFFICIENCY
Ft. Gordon Building 310	1,2,3	Nat Gas	High Flow ±2.85% Low Flow ±3.6%	±2.7% ±3.45%
	1	Oil	High Flow ±2.85% Low Flow ±3.6%	±2.7% ±3.45%

2.2 Chillers

Performance testing of existing chiller plants for Fort Gordon included: evaluation of the chillers' control systems, operation and maintenance procedures, cooling tower conditions and equipment and procedures for monitoring and recording system performance. The central chilled water plants were tested for system efficiency, and an examination of piping and plant connection equipment was conducted.

The purpose of this compilation is to present the results of the chiller efficiency tests performed on each chiller as scheduled in the chiller test plan of February 1986 (see Appendix 4.1.1). This report fulfills the requirements of specification Scope of Work for Fort Gordon, Georgia, as far as the actual testing and reporting of results and calculations. Analysis of these results and calculations are included herein.

Each chiller was tested in as normal an operating mode as possible with no changes to controls or operations other than to vary the load point for each chiller test condition. The chiller test plan of February 1986 was adhered to as closely as possible.

The required data has been collected, and the necessary calculations were completed to show the chiller efficiency expressed as chiller Energy Efficiency Ratio (EER). This report provides the specific chiller efficiency test information, including raw field data and the resulting calculations. A graph for each chiller which plots the resulting efficiency has also been produced in Appendices 4.2 and 4.3, Volume 2.

2.2.1 Building 25910

Efficiency tests were conducted on the Carrier chillers 2,3,4A and 4B from August 31, 1987 through September 2, 1987. Chiller number 1 was not tested because it was not part of the Scope of Work. Chillers 5, 6 and 7 (York 700T centrifugal chillers) were installed subsequent to this testing. The test results were recorded on Centravac Logs and included: evaporator and condenser pressure and temperature readings of inlets and outlets, control and panel readings, liquid levels, and amperage and voltage readings. Test data, graphs and centravac logs can be found in Appendix 4.2.1, Volume 2.

The specific chiller rates, lengths of test runs and the refrigerant used are as follows:

BUILDING	CHILLER	POINTS %	DURATION	REFRIGERANT
Fort Gordon:				
25910	1	Not tested	---	---
	2	50,65,80,100	2 hours	R-500
	3	50,60,80,100	2 hours	R-500
	4A	50,65,80,100	2 hours	R-12
	4B	50,65,80,100	2 hours	R-12
	5	Not tested	---	---
	6	Not tested	---	---
	7	Not tested	---	---

The following formulas are used in calculations throughout this report:

Heat transferred:	Q(BTUH) = 500*GPM*dT 1 Ton = 12,000 BTUH
Thermal Balance:	Q cond = Q evap + Q kw
Energy Efficiency Ratio:	EER = Q evap / Watts
Kilowatts used per Ton:	KW/ton = kilowatts/TONS evap

The data obtained through the testing of the chillers at Fort Gordon are provided in Appendix 4.2.1, Volume 2 for the building, including chillers 2, 3, 4A and 4B.

The Chiller Energy Efficient Ratios (EER) for those chillers tested in Building 25910 are summarized in the following table:

	Operating Points			
Chiller	100%	80%	65%	50%
1		---- Not Tested ----		
2	22.03	22.07	21.95	18.8
3	14.99	16.06	16.67	17.39
4A	12.06	11.77	10.80	8.71
4B	15.53	15.27	13.74	15.29
5		---- Not Tested ----		
6		---- Not Tested ----		
7		---- Not Tested ----		

2.2.2 Building 25330

Efficiency tests were conducted on two Carrier chillers on September 3, 1987. Chillers 3 and 4 (Trane 500T chillers) had not been installed at the time of testing and were not in the Scope of Work. The test results for the tested chillers were recorded on Centravac Logs and included: evaporator and condenser pressure and temperature readings of inlets and outlets, control and panel readings, liquid levels, and amperage and voltage readings. Additional test data and graphs for this building are located in the Appendix 4.3.1, Volume 2.

The specific chiller rates, lengths of test runs and the refrigerant used are as follows:

BUILDING	CHILLER	POINTS %	DURATION	REFRIGERANT
Fort Gordon:				
25330	1	50,65,80,100	1 hour	R-11
	2	50,65,80,100	2 hours	R-500
	3	Not Tested	---	---
	4	Not Tested	---	---

The following formulas are used in calculations throughout this report:

Heat transferred:	Q(BTUH) = 500*GPM*dT 1 Ton = 12,000 BTUH
Thermal Balance:	Q cond = Q evap + Q kw
Energy Efficiency Ratio:	EER = Q evap / Watts
Kilowatts used per Ton:	KW/ton = kilowatts/TONS evap

The data obtained through the testing of the chillers at Fort Gordon are provided in Appendix 4.3.1, Volume 2 for this building, including chillers 1 and 2.

The Chiller Energy Efficiency Rating (EER) for those chillers tested in Building 25330 are summarized in the following table:

	Operating Points			
Chiller	100%	80%	65%	50%
1	22.57	23.34	15.55	7.52
2	22.23	21.85	12.52	9.70
3	---- Not Tested -----			
4	---- Not Tested -----			

3.0 CONTROL SYSTEMS/OPERATION & MAINTENANCE

The existing control systems and operation and maintenance procedures were evaluated for the boiler and chiller plants at Fort Gordon to determine what equipment changes or operation and maintenance procedure changes could be made to improve the plants' performances.

3.1 General Plant O&M Procedures

At Fort Gordon, both the operation and maintenance of the heating and cooling plants are performed by contract under the Commercial Activities (CA) Program. The specific requirements for plant operation and maintenance are outlined in Army contract DABT11-90-C-0021, Part I - The Schedule - Section C - Description/ Specifications/Work Statement, a copy of which is included in Volume 2, Appendix 2.0. This document places full responsibility for the operation, maintenance and management of the heating/cooling plants and associated equipment with the Contractor. In addition it outlines:

1. Minimum staffing and qualifications levels
2. Representative systems and equipment
3. Required levels of maintenance and readiness
4. Standards compliance for maintenance/repairs
5. Frequencies of certain maintenance and operation activities
6. Requirements for maintaining plant logs
7. Energy Conservation Program compliance requirements
8. Contractor maintenance management requirements

3.1.1 Preventive Maintenance Procedures

The Contractor is responsible to develop and implement a preventive maintenance program for the heating/cooling plants and to " ... perform the preventive maintenance and equipment overhaul of the heating and cooling plants in accordance with accepted engineering practices and manufacturer's manuals."

The Contractor has developed detailed preventive maintenance schedules that track equipment preventive maintenance (PM) requirements on a microcomputer. A copy of a representative schedule has been included in Volume 2, Appendix 2.3. A similar schedule exists for each plant.

In addition to the PM schedules, each piece of equipment has an associated index card on which each PM action is recorded. These cards are maintained at the plant where the equipment is located and provide a written history of the PM performed on each separate piece of equipment.

In Building 25910, a lead mechanic is responsible for PM and makes weekly PM assignments to the operators and maintenance mechanics. In Building 25330, the four shift operators are jointly responsible for performing PM. The plant supervisor is responsible to check the logs to ensure that the maintenance has been performed.

In Building 310, one mechanic is assigned responsibility for PM performance and record keeping; however, he receives assistance from other operating/maintenance personnel, as necessary. As in the case of Buildings 25330 and 25910, the plant supervisor is responsible to check the logs to ensure that the maintenance has been performed.

There is currently no mechanism to "close the loop" on the computerized maintenance management system. The computer program generates a preventive maintenance schedule and that schedule is acted upon to ensure that PM is performed; however, information is not returned to the computer to show that the PM has been performed. Additionally, unscheduled maintenance and repairs are not recorded. There is, consequently, no central historical data base of equipment maintenance and repair; nor is there an easy way to track the effectiveness of the maintenance management system. More significantly there is no single data base of maintenance and repair history information upon which trend analysis can be performed to identify potential improvements to the maintenance management system and to project upcoming maintenance/repair resource requirements.

3.1.2 Plant Operating Procedures

With respect to heating and cooling plant operations, the contract is largely a performance-type specification setting forth only broad parameters for operation (i.e. "provide 24 hour operation ...") and establishing minimum standards (i.e., minimum qualifications for operators). The operations management and implementation of specific procedures are left largely to the discretion of the Contractor. In this case, the Contractor has chosen to promulgate implementing procedures through the issuance of a proprietary document referred to as a "Department Guides". The Department Guides for heating and cooling plants contains fairly specific guidance on the following topics:

1. Safety
2. Energy Conservation
3. Plant Operations
4. Water Analysis Treatment
5. Fuel Oil Operating Procedure
6. Chiller Operating Procedures
7. Boiler Operating Procedures
8. Economizer Operation

With the Contractor's permission, a copy of this document has been included in Volume 2, Appendix 2.2.

This appears to be, on the whole, a very good document; however, it should not be considered a static document nor is it as complete and specific as it should be. It should be subject to periodic (i.e; annual) review and revision, and the Contractor and government should continue to address additional appropriate topics for inclusion. While this document covers the major pertinent topics, there are other subordinate topics appropriate for inclusion. For example, there is no discussion on logging of plant operating parameters. Additionally, some topics need more specific coverage. It is noted, for example, that energy conservation is addressed but that the only specific guidance provided is chilled water temperatures to use in the cooling season.

3.1.3 Operator Qualifications

Operator qualifications are ensured by two mechanisms. The first is the contract, and the second is the Contractor's licensing policy.

The contract states that, "The contractor shall provide proof in writing to the contracting officer that the plant foreman, and all operators, electricians, instrument mechanics and maintenance mechanics meet the minimum standards specified below." The contract later defines the minimum operator qualifications as follows:

> 5.9.3.2.3 Plant Operation Personnel. Plant operating personnel employed by the contractor shall have a minimum of three years experience in operating high pressure steam or pressurized high-temperature water generating plants or shall have completed a three year apprenticeship program and be qualified to determine causes of malfunctions of generating plants and take corrective actions; shall be qualified to perform any type of boiler water analysis as well as a combustion analysis and stack gas analysis and provide necessary correction; and perform operator and preventive maintenance at all plants. At least one operator shall be in attendance at Buildings 25330 and 310 at all times. A minimum of two operators shall be in attendance at Building 25910 at all times.

To ensure compliance with these requirements, the Contractor requires the operators to be licensed stationary engineers. The Contractor's policy is that within one year of hiring, operators will be licensed by the Georgia State Association of the National Institute for Uniform Licensing of Power Engineers, Inc. Currently, all operators are licensed in Classes 2-4, and the Central Plant Foreman is licensed in Class 1.

This combination of operator qualification requirements probably provides better control and results in better qualified operators than would normally be obtained through government hiring practices.

3.2 Boilers

The subsequent sections will describe the following control and operational issues: manual and automatic controls operations, flame safety operations, burner operations, maximum and minimum control operations, feedwater system operations, boiler ignition system operations, casing repairs, oxygen analyzer additions, boiler sizing, training of personnel, fuel analysis, boiler tuning, EMCS monitoring, water treatment and equipment optimization.

3.2.1 Building 25330

The operating controls for this building are composed of the manual switches, starters and boiler firing controls originally installed. There have been no significant modifications made to this installation since its construction.

3.2.1.1 Controls Operation, in Manual and Auto:

At the time of boiler testing, it was noted that the controls needed attention immediately. It was noted that the controls, in some cases, shut the boilers down at firing rates below 15% and that none of the recorders were working at all. While some of the problems have since been corrected, it was noted in a follow-on site visit in November, 1990 that many problems still exist.

Both the master and submaster controllers are generally functional; however, there is no operational O_2 trim and one cascade level controller is inoperative. The controls are the originally installed Cleveland controls, and, while they are currently functioning, obtaining repair parts has become a major problem. In fact, the operating and maintenance personnel have had to resort to scavenging for parts to keep the feedwater control system operational. Relays for the feedwater valve actuators are noted to be failing with regularity.

The fuel/air ratio is controlled acceptably while firing on gas even at the upper and lower ends of the firing scale. The boilers were not firing on oil during the 1990 visit, but it was reported by the operators that there is a problem with the boilers smoking while firing on oil. This is generally indicative of a too high fuel/air ratio and indicates the need for nozzle replacement, correct fan stroking or controls calibration.

Boiler start-up is completely manual. In view of the fact that there is generally only one operator in this plant, this is less than an optimal procedure.

The limit cut-out controls are currently working properly; however, a minor problem was noted with the flame safety system.

Given the advanced age of the boiler controls, the difficulty in obtaining repair parts, the outdated control technology in use, the long-term inability to get the controls to properly control the F/A ratio on oil and the inoperable state of the recorders and O_2 system, it is strongly recommended that the entire system be replaced with new state-of-the-art digital controls and recorders.

3.2.1.2 Flame Safety System Operation:

As previously noted, minor problems have been experienced with the flame safety system. Safety limits, if functioning correctly, will shut the burner down for out-of-limit condition and will not cause a nuisance shut-down when within limits. The system installed is adequate and current, but it needs to be serviced and repaired to work correctly. Limits should be regularly tested and maintained to assure operational readiness. A regularly scheduled operational check should be performed on the system and each part with PM as required.

3.2.1.3 Burner Operation:

Several things were noticed during testing that could improve burner operation. Nozzles need to be checked for wear and correct application for burning #2 fuel oil. Forced Draft (FD) fans need to be serviced and cleaned. O_2 units need to be put back in operational state or replaced. The gas burners show signs of cracks in the rings, and the gas would not burn cleanly with normal excess air. It is recommended that the burners be serviced, inspected and cleaned. Repair or replace defective parts. Replace the oil nozzles. Make sure the new oil nozzles installed are correctly sized for the conditions and maximum capacity for these boilers. If the gas burner rings are burned out or cracked, they should be replaced at once.

3.2.1.4 Boiler Maximum Capacity:

During testing, it was noted that the boilers had been reduced in maximum fuel input by almost 25%. Boilers should be allowed to reach full capacity if needed. It is recommended that the problem be corrected to allow the boilers to reach maximum fire, or if less than maximum is desired, determine exactly what rate is to be used, and set the combustion and feedwater system to that maximum rate.

3.2.1.5 Boiler Minimum Capacity:

During the boiler testing, boilers were not able to go to a minimum fire position without shutting off. This has since been corrected. Because these boilers spend most of their time at low fire, it is most important that the system function efficiently at low fire. As a general recommendation, the controls should allow the burner to turn down to the lowest firing condition for which a stable, clean, and safe flame pattern is attainable. This setting should still allow reliable burner ignition every attempt. Normal low fire should be 20% of capacity or less.

3.2.1.6 Boiler Feedwater System Operation:

Feedwater valves don't appear to sufficiently respond to load changes. During testing, operators had difficulties with electrical components going bad, which closed feedwater valves, stopping flow to the boiler and causing a low water shutdown of the boiler. Interviews with on-site personnel indicated that as of October 1990, response was still inadequate.

The feedwater deaeration (DA) system needs immediate repairs. During testing, the Spence regulating valve on the steam supply line to the DA tank was not operating properly, and consequently, steam was not being supplied to the tank. During the 1990 follow-on site visit, it was noted that the DA tank was operating at 190°F and 7 psig. At these conditions, the feedwater will not be adequately deaerated. At a DA pressure of 7 psig, the temperature of the feedwater should be at least 232°F to ensure full expulsion of entrained gases. It is imperative that this system be repaired immediately since the existence of non-condensible gases in the boiler feedwater is the biggest single cause of boiler corrosion.

3.2.1.7 Feedwater Treatment:

During the site visits and boiler testing, evidence of significant corrosion problems has been noted. Particularly worrisome is the recurring corrosion of the cascade heaters. Because the cascade heaters are pressure vessels subject to significant thermal shock, weakening caused by corrosion could be dangerous. The cascade heaters in both Buildings 25330 and 25910 have been patched repeatedly at the end cap welds. Station operating personnel have stated that they believe the leakage is due to stress cracks; however, it is just as likely that interstitial corrosion in the welds is the cause.

In addition, corrosion was noted in the form of scale build-up in piping and surface corrosion at flanges and other joints.

It has been previously addressed that the feedwater deaeration system is not operating properly. The resulting existence of non-condensible gases in the feedwater greatly increases its corrosivity.

In addition to deaeration, the feedwater make-up is softened to reduce scale, and the boiler water is treated internally (i.e. in the steam drum) to reduce scale and control pH. At the time of the 1990 site visit, it was reported that the chemical injection system and the water softener were working. However, it was noted that prior to being recently rebuilt, the softening system had been inoperative for some time.

While there is no immediate effect on plant performance when the water treatment systems are inoperative, the long-term damage caused can be so significant that operational water treatment systems should be considered to be as important and necessary to the proper operation of the plant as are limit cut-outs, level controllers or flame safety devices. It is recommended that water treatment and DA systems receive the same maintenance and repair priority as any other system critical to the operation of the plant.

3.2.1.8 Make-up Water Reductions:

Make-up water usage generally ranges from 2000-5000 gallons per day per boiler in operation. There have been, however, several periods of time where the make-up water usage jumps to over 15,000 gallons per day. The normal make-up of 2000-4000 gallons per day amounts to 1.4 - 2.8 gallons per minute. That level of make-up indicates the need for some distribution system maintenance and presents a reasonable opportunity for energy savings. 15,000-20,000 gallons per day represents very serious leakage that costs significantly in terms of energy wasted. Those leaks should be promptly repaired.

3.2.1.9 Boiler Refractory and Casing Repairs:

Each year, combined with the annual boiler cleaning and inspection, the boiler interior refractory and insulation should be inspected and repaired as needed. The boiler casing should be checked for hot spots, leaks and repaired as needed.

3.2.2 Building 310

3.2.2.1 Controls Operation, in manual and auto:

Controls respond acceptably in an auto mode, with the load changes on the system. In manual they held the set rates acceptably. Controls should be periodically checked and adjusted as needed. A combustion technician with experience on Peabody Burners and the combustion controls should test and properly tune the burner and combustion controls for proper, clean and efficient firing at all firing rates on both fuels; then train the operators to maintain that proper operation.

3.2.2.2 Flame Safety System Operation:

During testing, operators had trouble getting boilers to light on occasions. Safety limits, if functioning correctly, will eliminate this problem. It is recommended that checks and adjustments to limits be done as needed to prevent nuisance problems. Develop a regularly scheduled testing program to maintain the ignition and flame safety system. Test, log, and repair the flame safety as necessary.

3.2.2.3 Burner Operation:

On natural gas, burners operated acceptably during testing except in some cases where combustion was not complete, or the fire would be blown out or off the gas ring. Boilers wouldn't run acceptably on oil and smoked excessively. It is suggested that set points be adjusted on gas to allow proper mixture of gas and air when operating. Investigate to see if information can be found for maximum capacity for No. 2 fuel. Replace nozzles if that hasn't been done. Control of No. 2 fuel through nozzles set up for No. 6 can't be done. Improper nozzle size and improper air register adjustments are the major reasons why boilers were smoking excessively on oil.

3.2.2.4 Boiler Maximum Capacity:

Boilers will not reach maximum capacity. Fuel input is about 91% to 96% maximum. Since plenty of air is available, it is apparent that burner tuning is needed. It is recommended that a maximum desired input be agreed upon and controls set to where dependable safe and clean operation is obtained.

3.2.2.5 Boiler Minimum Capacity:

Boilers were able to turn down to minimum fire and run reasonably well. The system seems to work well at low fire. Each boiler would run cleanly at 25% firing rate or below. It is recommended that adjustments are checked and points set on limits for desired input.

3.2.2.6 Boiler Feedwater System Operation:

This system needs attention and service immediately. Corrosion and scaling was noticed in the feedwater (FW) piping when test spool pieces were installed to measure feedwater flow. Feedwater valves on boilers don't work well at all. They don't respond to signals from controls the way they should. Feedwater temperature is extremely low causing a lot of undetected problems. The deaerator and boiler feed system is not working to preheat and deaerate the feedwater correctly. It is recommended that consideration is given to replacing feedwater piping. Service feedwater valves to where they operate in such a way to supply adequate water to the boiler, or replace the feedwater control valves. Repair or replace the deaerator and boiler feedwater system. The boiler feedwater preheat system should be operated to protect the economizers. Preheat to 240°F to fully protect the economizers from acid dew point caused corrosion.

3.2.2.7 Boiler Ignition System Operation:

Boilers would light on gas acceptably, but on oil, operators had difficulties. It is recommended that necessary servicing be provided to eliminate nuisance problems causing unnecessary shutdowns and difficulties getting boilers into operation.

3.2.2.8 Steam Quality:

Steam moisture content of 3/4% to 1-3/4% was observed on all boilers at all loads. Moisture contents of over 1% at low firing rates are unusual. The carry over content should not be that high. Check the drum level being carried as it may be too high. Check the internal steam separator baffles for condition.

3.2.2.9 Oxygen Analysis:

At the time the boilers were tested in 1988, the O_2 units were inoperative. According to plant operating personnel, they are now (as of October 1990) working properly. It is essential that this equipment be maintained in top operating condition. Without O_2 analysis or trim equipment, it is difficult to impossible to trim the burners for most efficient operation.

3.3 Chillers

During the chiller testing activities, it was observed that the chillers are currently being sequenced manually to meet observed load conditions. All plants have microprocessor controls, and should be evaluated for automatic sequencing of machines, with corresponding control of towers and pumps. Automatic sequencing would optimize system efficiency.

Actual load profile information is necessary to establish a sequencing plan. Unfortunately, analysis of the detailed load profile information that was provided for this study has shown it to be erroneous. This information, which has been confirmed as inaccurate by Ft. Gordon and C.O.E. personnel, is of essentially no use to this study.

In addition, because the efficiency of the chillers is substantially affected by cooling tower performance, historical data concerning cooling tower performance are necessary to ensure most efficient equipment sequencing. As will be discussed later, cooling tower condition and performance is a significant concern, particularly at Buildings 25910 and 310.

During chiller testing activities, it was noted that chiller controls and instrumentation are not under a regular preventive maintenance program. Further detailed equipment operation procedures were not available.

The subsequent sections will describe the following recommended control systems and operational improvements: installation or repair/reinstallation of microprocessor controls; provision of additional metering equipment; Energy Monitoring and Control System (EMCS) interface; development and implementation of additional detailed equipment-specific operation and maintenance guides; cooling tower sequencing; cooling tower maintenance and repairs; improved log maintenance practices; and refrigerant use.

3.3.1 Plant Control Systems

Though much of the water chilling equipment installed is equipped with microprocessor controls, the equipment is sequenced manually by the operating personnel. Sequencing of chillers is based solely on chilled water temperatures. The following guidance is provided in Department Guide No. 40-09-004:

a. The following chilled-water temperatures will be used as a guideline for cooling systems operations:

(1) Bldg. 310 - Max. temp. 52°F, min. 44°F, ideal 47°F
(2) Bldg. 25330 - Max. temp. 55°F, min. 46°F, ideal 49°F
(3) Bldg. 25910 - Max. temp. 53°F, min. 45°F, ideal 48°F

b. The minimum number of chillers required to maintain these chilled water temperature ranges will be used at all times.

It is assumed that the referenced temperatures are chilled water return temperatures. Note that these temperatures are maintained by the operators manually sequencing the chillers. The chiller controls operation is automatic only to the extent that the compressor inlet vanes are controlled by the chiller leaving water temperature.

The condenser water pumps are manually sequenced with the chillers and the cooling tower fans cycle in response to cooling tower sump temperatures. The chillers are each generally served by a dedicated cooling tower cell. The cooling towers and chillers are not connected by common supply and return headers to provide redundancy and optimum cooling tower-to-chiller matches under varying conditions.

3.3.2 Metering Equipment

The chillers are generally well instrumented. All chillers noted are equipped with chilled water and condenser water supply and return water temperature thermometers, and the microprocessor controlled machines are capable of providing other information including:

- Refrigerant pressures and temperatures
- Oil pressure and temperature
- Motor amps
- Motor volts

Significantly, however, there is no chilled water or condenser water flow information recorded by the operators. Without this information, it is not possible to make an accurate assessment of heat flow. Heat flow information is required to establish load profiles and to calculate efficiency indicators such as the Energy Efficiency Ratio (EER) and kilowatts used per ton of refrigeration.

3.3.3 Energy Monitoring and Control System (EMCS) Interface

Ft. Gordon has a very successful energy conservation program centered around a capable EMCS. However, this system is currently tied only to the load end of the cooling system.

As of late 1990, the EMCS had reached the capacity of the computing equipment for sensor/control interfaces. A system expansion is planned, however, that will allow for additional interfaces. Upon completion of that expansion, it is recommended that the EMCS be expanded to the chilling equipment in two phases.

The Phase I should be limited to monitoring certain plant operating parameters. Suggested parameters to be monitored are:

- System chilled water supply and return temperatures

- System chilled water flow rate
- Make-up water flow rate and totalizer for chiller water
- For each individual chiller and cooling tower:

    1) Chilled water supply and return temperatures
    2) Condenser water inlet and outlet temperatures
    3) Chiller motor voltage
    4) Chiller motor amperage
    5) Chilled water flow rate
    6) Condenser water flow rate
    7) Cooling tower fan voltage/amperage
    8) Condenser water pump voltage/amperage
    9) Condenser water make-up rate

The Phase II should include the ability to centrally control chilling equipment through the EMCS. Equipment to be controlled through the EMCS should include:

- Chillers
- Cooling towers
- Condenser water pumps
- Chilled water pumps
- Remotely operated valves for system configuration

Completion of the Phase I will enable the EMCS operator to:

- Monitor system performance
- Determine the most efficient chiller/cooling tower configurations for various load conditions
- Provide guidance to the operators to ensure efficient plant operation
- Establish a detailed and credible data base of cooling load and system performance data

From the data obtained during Phase I, a sequencing plan can be developed for use in Phase II implementation.

After completion of Phase II, it would be possible to actually operate the water chilling equipment remotely from the EMCS station. In fact, if properly implemented, it would be possible to automatically sequence the equipment in the most efficient configurations for the given load. It will still be necessary, however, to retain operators in the chilling plants on at least a rotating basis to monitor the operation of the equipment.

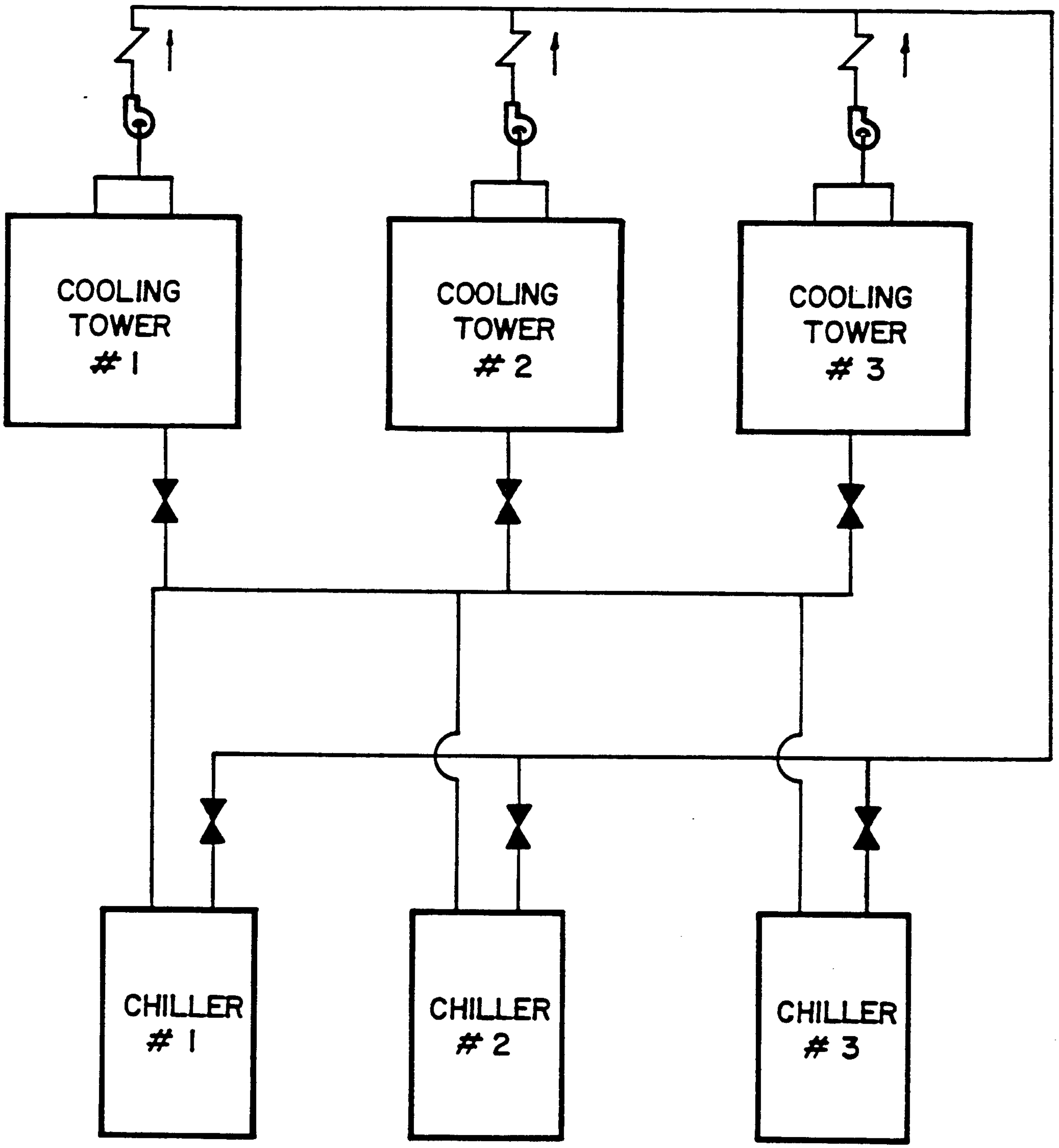
3.3.4 Operation and Maintenance Guides

As noted earlier, the Department Guide issued by the Contractor to provide guidance to the operators and stationary engineers is a good document; however, it is not without room for improvement. It is important that this document be periodically reviewed and revised to ensure completeness and accuracy. One area of immediate concern is the lack of guidance for logging plant operating data. A review of the logs has shown that there is disparity between plants and operators with regard to logging information. As a result, the usefulness of the information logged is degraded.

3.3.5 Cooling Tower Sequencing

As currently configured, it is not possible to sequence the cooling towers as dictated by wet-bulb temperature nor to configure cooling tower/chiller combinations in the most efficient configurations. If the cooling towers are replaced in the future, it is recommended that you consider piping the cooling towers as shown for the generic case in figure 1 on the following page. As can be seen from this schematic drawing, piping the chiller condensers to the cooling towers in this manner allows complete flexibility in chiller/cooling tower combinations.

FIGURE 1



GENERIC CONDENSER WATER PIPING SCHEMATIC

FORT GORDON U.S. ARMY ENGINEER DISTRICT, SAVANNAH	AUGUSTA, GA. CORPS OF ENGINEERS SAVANNAH, GEORGIA

ENERGY AUDITS OF BOILER & CHILLER PLANT

ENERGY ENGINEERING ANALYSIS PROGRAM

WATSON ENGINEERING, INC.
33920 U.S. HIGHWAY 19 N. SUITE 300
PALM HARBOR, FLORIDA 34684

3.3.6 Cooling Tower Conditions

The cooling towers at Ft. Gordon are generally in poor condition. This results in substantially reduced chiller capacities and efficiencies since the deteriorated tower conditions result in a reduced capacity to reject heat from the condenser water. Additionally, condenser make-up water and water treatment costs increase significantly as the deteriorated cooling towers "bleed" water to the atmosphere in the form of small water droplets instead of carrying heat away in the form of water vapor. A normally functioning cooling tower should use 1.6 to 2.0 gallons per hour per ton of refrigeration; however, that quantity can be substantially increased if the towers are not operating properly. Though separate cooling tower make-up water logs are not maintained, visual observation of the cooling towers (at Building 25910) in operation indicates a serious bleed problem. Specific cooling tower conditions are outlined in the following paragraphs.

3.3.6.1 Building 25910:

Building 25910 has six (6) double-cell cooling towers; 1, 2, 3, 4A/B, 5 and 6. Towers 1-3 and 4A/B each service one chiller correspondingly numbered. Towers 5 and 6 service chillers 5, 6 and 7. These two towers are connected by a sump equalizer line and must be operated together. If only one of these two towers is operated at once, the sump of the other tower will overflow.

Of the six (6) towers at Building 25910, only one, 4A/B, is in good condition. Towers 1, 2, 3, 5 and 6 all require major repair or replacement. The media in these towers is redwood slat and varies in condition from partly deteriorated to totally collapsed. The distribution decks are in generally poor condition and some of the cooling towers have wooden pipes that leak badly. The tower structures themselves are of corrugated asbestos sheets and are in fair condition. Condenser water temperatures returning from cooling tower #3 have been recorded as high as 95°F, and return condenser water temperatures around 90°F are common. When these cooling towers are in operation, the bleed is so bad that the bleed condenser water covers the area behind the building like a heavy mist. It is recommended that cooling towers 1, 2, 3, 5 and 6 be replaced with new generation PVC media-filled induced draft cooling towers or, at a minimum, that they be remanufactured by the manufacturer.

3.3.6.2 Building 25330:

The four (4) chillers in Building 25330 are served by two dual-cell cooling towers.

Chillers 1 and 2 are served by an old cooling tower of undetermined manufacture. It has redwood slat cooling media that is in poor condition; the side walls are in poor repair, and the decking needs to be replaced. This tower bleeds heavily when in operation. It is recommended that it be rebuilt with PVC media or that it be replaced with a current generation cooling tower.

Chillers 3 and 4 are serviced by a newer Marley double-flow cooling tower. It appears to be in excellent condition and no action other than ongoing water treatment and periodic preventive maintenance is indicated.

3.3.7 Log Maintenance Practices

Chiller plant log maintenance practices at Ft. Gordon are generally good; however, some room for improvement exists.

For purposes of identifying energy conservation opportunities, the single most important price of missing data are chilled water and condenser water flow rates. The following flow information should be recorded:

- Chilled water supply/return for the system
- Chilled water supply for each chiller
- Condenser water inlet or outlet for each chiller condenser

Additionally, it is important to meter and record make-up water for the chilled water system and for the cooling towers. Without this information, you may be wasting large amounts of water, chemicals and energy unknowingly.

3.3.8 Refrigerants

All of the centrifugal chillers observed and/or tested as part of this study use R-11, R-12 or R-500 refrigerant. While this does not pose an immediate problem, it is worthy of note that, because of their ozone depletion potential, the Montreal Protocol has targeted these refrigerants for elimination by the year 2000, and the USEPA has promulgated a final rule, under the authority of the Clean Air Act, to enforce the provisions of the Protocol. In the interim, ozone depleting chemicals (including R-11, R-12, and R-500) will be subject to production and import quotas.

The major refrigerant manufacturers are working to develop new, environmentally safe refrigerants, but until they are developed, it appears that R-22 (which is one-tenth as damaging to the ozone layer as R-11 and R-12), and R-134 will be the refrigerants of choice for large centrifugal chillers. Unfortunately, due to their substantially different physical characteristics, it is likely that some modifications to existing chillers will be required to accommodate their use.

It is strongly recommended that a refrigerant conversion program be developed for implementation during the next five years. Failure to do so will result in major refrigerant procurement problems in the late 1990's.

4.0 SPECIFIC EFFICIENCY IMPROVEMENTS

In accordance with the Scope of Work paragraph 3.6, twenty-six potential specific efficiency improvement items have been considered. Potential efficiency improvements are described in the following paragraphs.

4.1 Controls to Assure Proper Combustion Air/Fuel Ratios

The proper control of the air-fuel ratio in the operation of a boiler is critical to its performance. Insufficient air flow will cause incomplete combustion of the fuel leading to poor boiler efficiency. Excessive air flow can cause steam temperature control problems caused by the increased mass flow rate through the boiler, as well as inefficiency due to the energy consumed to heat the excess air.

This item has been combined with the specific efficiency improvement entitled, Reduce Excess Air. See Section 4.7.

4.2 Feedwater Treatment

The proper chemical treatment and deaeration of the boiler feedwater is essential to the life of the boiler. At the elevated temperatures encountered in the boiler, the presence of dissolved oxygen in the feedwater will increase corrosion levels dramatically.

4.2.1 Building 25330

Heavy deposits in the feedwater lines were noted when installing feedwater measurement instrumentation. Visual inspection revealed approximately a 50% inner diameter reduction due to these deposits. This buildup of deposits indicates little or no feedwater treatment. This was confirmed by Mr. Carl Stein, who reported that at the time of testing the zeolite softeners had been out of operation for two years. During the 1990 site visit, it was noted that the water softening system had been repaired within the preceding year.

Feedwater treatment is not intended to improve efficiency, but to extend the life of the boiler. Scale removal would increase efficiency slightly; however, an economic justification would be difficult to quantify, as the primary purpose is to prevent boiler failure.

Another important component of feedwater treatment is deaeration of the feedwater. This is accomplished by raising the temperature of the feedwater to above the saturation temperatures of the entrained gases (i.e. air) such that the gases are expelled from solution and those gases are vented to the atmosphere.

During the 1990 site visit, it was noted that the deaeration tank in Building 25330 was operating at 190°F and 7 psig. At this temperature and pressure, the feedwater will not properly deaerate, and boiler tube corrosion will result.

4.2.2 Building 310

Heavy deposits in the feedwater lines were also noted in Building 310 when installing feedwater measurement instrumentation. Visual inspection revealed approximately a 50% inner diameter reduction due to these deposits. This buildup of deposits indicates little or no feedwater treatment. Also, it should be noted that a buildup of deposits in the boiler tubes will diminish the heat transfer and ultimately cause the tubes to fail.

The data taken around the deaerator, along with interviews with the boiler operators, indicate that the internals of the deaerator are in a state of disrepair. This will result in internal corrosion, significantly reducing the life of the boiler.

Correcting these situations will incrementally improve the efficiency of the boilers, so no economic justification was performed. However, correcting these situations is good boiler practice, and the cost is substantially less than replacing the boiler tubes or purchasing an entire new boiler.

4.2.3 Building 25910

During the 1990 site visit, it was noted that the feedwater deaeration system in Building 25910 is completely inoperative and has been for some time. It is imperative that this serious deficiency be corrected as soon as possible in order to minimize additional damage to the boilers.

4.3 Waste Heat Recovery

Due to the inherent inefficiencies created by the manufacturing process, a boiler will discharge heat from its stack in the form of flue gases, as well as in the form of heated water discharged to control corrosion or sediment buildup.

4.3.1 Building 25330

No blowdown was noted during inspection of this boilerhouse, and the plant operating logs do not indicate a blowdown. It is assumed that a 3% continuous blowdown exists. As shown in section 4.3.4 of the Appendix, Volume 2, the cost of the equipment for a blowdown heat exchanger system far outweighs the savings that would be experienced. Therefore, a blowdown heat exchanger is not recommended for this system.

4.3.2 Building 310

Only continuous blowdown was noted during inspection of this boilerhouse. As shown in section 3.3.4 of the Appendix, Volume 2, the cost to implement a blowdown heat exchanger system far outweighs the savings that would be experienced. Therefore, a blowdown heat exchanger is not recommended for this system.

4.4 Operation and Maintenance Procedures

The conditions under which mechanical equipment operates many times are so severe that premature failure occurs, if proper operation and maintenance procedures are not followed. The high temperatures and pressures encountered will cause metals to fatigue and fail in a relatively short time, if not controlled and anticipated.

4.4.1 Boilers

4.4.1.1 Building 25330:

4.4.1.1.1 Stack Temperatures. Test results obtained on boiler #1 showed a higher than normal stack temperature. Baseline performance data for these Nebraska boilers, shown in Appendix 3.3.2, Volume 2, indicated an expected boiler exit gas temperature of 515°F and 525°F for gas and oil, respectively, at full load. Test data shows an exit gas temperature of 600°F for gas and 650°F for oil. From this information, it can be concluded that heat transfer from the gas to the water in the boiler is being retarded, or the gas is bypassing the boiler heating surface.

The high boiler exit gas temperature is significant in that it represents approximately a 3% loss in efficiency. It is probable that the baffle wall has holes, or similar damage which would allow the hot flue gas to bypass the generating bank. Internal inspection was not permitted to confirm this problem. However, it is noted that baffle wall holes are easily repaired by patching with refractory.

It should also be noted that high stack temperatures lead to premature stack deterioration.

4.4.1.1.2 Soot Blowdown. During operator interviews, Mr. Ed Atkinson reported that when the boilers are firing on gas, soot is blown down once a week. When the boilers are firing on oil, the soot is blown down once a day. These blowdown intervals are acceptable as blowdown is a necessary part of boiler upkeep. Without soot blowdown, heat transfer would be impeded and increased stack temperatures would result.

4.4.1.1.3 High Pressure Safeties. The safety on boiler #2 lifted several times during testing. High pressure shutdown systems are in place and should be reset to prevent this from happening in the future. Repeated lifting of the safety will lead to mechanical failure and require a forced shutdown to repolish the seal and repair it. Resetting the high pressure shutdown system will not result in any improvement in efficiency, so no economic justification was performed.

4.4.1.1.4 Fuel/Air Adjustment. Currently, the boiler fuel/air ratio is adjusted by visual observation of the burner flame and stack gases. This less-than-desireable operation method generally results in reduced boiler efficiencies due to the introduction of too much excess air in the boiler combustion charge. However, due to the lack of automatic O_2 trim or O_2 analyzers for manual O_2 trim, there is currently no way for the operators to improve the combustion efficiency of the boiler plants. It is strongly recommended that O_2 analysis equipment be purchased to allow for the proper adjustment of the fuel/air ratio. This topic is covered more fully in Section 4.7.

4.4.1.1.5 <u>Monitoring and Logging Plant Operating Parameters</u>. It is currently impossible for the plant operators to monitor plant efficiency since the necessary metering and instrumentation is either non-existent, non-functional or inaccurate.

It is recommended that the plant instrumentation be upgraded so that critical information concerning the plant operation and efficiency can be monitored and logged. At a minimum, instrumentation for the following applications should exist and should be regularly maintained and calibrated:

- Steam pressure
- Steam flow
- Feedwater Flow
- Fuel Flow (natural gas and oil)
- Flue Gas Temperature
- O_2/CO_2 Analysis
- Make-up Water flow
- Make-up Water temperature
- Economizer water temperature
- Feedwater heater temperature
- Feedwater heater pressure
- Deaerator temperature

- Deaerator pressure
- Natural gas pressure
- Natural gas temperature
- Fuel Oil pressure
- Fuel Oil temperature
- Condensate pressure return
- Condensate return temperature
- Atomizing steam pressure

Following the metering and instrumentation repairs and upgrades, a guide worksheet and appropriate training should be developed to assist the operators in monitoring and logging the appropriate information and computing boiler efficiency.

Alternatively, with appropriate interface equipment, the Ft. Gordon EMCS could be utilized to record the appropriate data and to compute and record boiler operating efficiencies. While it is currently (as of late 1990) not possible to utilize the EMCS in this fashion due to equipment limitations, it is recommended that this course be pursued after the pending EMCS expansion.

4.4.1.2 Building 310:

4.4.1.2.1 Fuel/Air Adjustment. Boiler #1 was tested on #2 fuel oil and severe smoking was experienced. Mr. Bob Hampton of Johnson Controls thought it wise to discontinue testing. Boilers #2 and #3 could not be fired successfully on #2 fuel oil. It was apparent that the combustion controls have never been set for oil. For the purpose of an economic justification, a 50% increase in efficiency was assumed since no data was available. The calculations in the economic justification demonstrate that it is not economically feasible to calibrate these three boilers based on the fuel usage of 5,800 gallons in 1987 reported by Annette Corley, Utilities Billing Clerk.

It is important to note, however, that the overriding consideration in this case in not economic justification but Clean Air Act compliance. Because these boilers are operated on #2 oil during gas curtailment, it is mandatory that the burners operate cleanly on #2. It is not optional, and the decision to properly calibrate the burners and controls should not be driven by the economics of burning #2 oil.

During the 1990 site visit, the boilers were operating on gas. Consequently, observation of boiler operation on oil could not be made. Interviews with plant operating and maintenance personnel indicate, however, that there is still a problem with smoking while operating on #2 fuel oil. This problem must be corrected. A first step is to ensure that the burner nozzles are properly sized for #2 oil. The next step, in either case, is to properly calibrate the controls.

The burners appear to burn clean while operating on gas.

4.4.1.2.2 <u>Insulating Atomizing Steam Lines</u>. None of the atomizing steam lines in this boilerhouse are insulated. Although there is no economic justification for insulating these lines, doing so would reduce the sparklers and carbon carryover and possible sulfur deposition, which may be occurring within the boiler. A small efficiency increase will result from this improvement.

4.4.1.2.3 Monitoring and Logging Plant Operating Parameters. In the Daily Operations Logs provided for this study, the boiler plant operating parameters recorded were: pounds of steam made, outside air temperature, make-up water, flue gas temperature and gas used. While this information is useful, it is insufficient in terms of determining plant operating efficiencies. It is recommended that the parameters listed in paragraph 4.4.1.1.5 be measured, recorded and utilized in determining boiler efficiency. As in the case of Building 25330, this information can be manually observed and recorded, and efficiencies can be calculated by the operators; or alternatively, the information can be gathered, utilized and recorded by the EMCS.

4.4.2 Chillers

Observations of operations and maintenance procedures were conducted during initial testing activities; however, they may not represent current practices at the installation. The greatest concern with O&M on chillers would stem from the apparent lack of a process for maintaining critical performance data on machine and system operations.

Records of specific maintenance and repair of individual equipment components are reportedly available. However, log information on system performance; including such indicators as flow rates, temperature changes, and pressure drops, has not been produced. Logs which purportedly demonstrate BTU loading on chillers for eight-hour periods have been provided and reviewed. However, the data are inconsistent with the equipment utilization. (See section on Load Profile Analysis.)

Equipment performance characteristics are key measurements used to develop a cost effective preventive maintenance program. The data are vital in system diagnostics, and in making informed decisions on equipment repair or upgrade. At this time, however, sufficient equipment performance information is not available.

Following the 60% submittal, another site visit was conducted to update our analysis of current operations and maintenance procedures so that specific improvements could be addressed. That site visit confirmed our previous suspicions regarding the inadequacy of system performance data being measured and logged. In fact, it was found that, in many instances, the instrumentation necessary to measure system performance was either non-existent or inoperative.

Additionally, because pressure data had not been produced, a set of pressure gauges was included with the test equipment for post - 60% site visit. However, based on assurances that the required pressure test data were already recorded and would be produced, pressure tests were not conducted. It was subsequently determined that the data do not exist.

From the foregoing discussion, it should be clear that insufficient data exist to make equipment specific recommendations to increase the efficiency of the chiller equipment. However, from observation and discussion at the most recent site visit, a number of general recommendations can be made.

4.4.2.1 Established Procedures for Operation and Maintenance:

Currently, the plants are operated based solely on operator experience and knowledge and utilizing the zone CHWS and CHWR temperatures as controlling system parameters. There are no established procedures for chiller sequencing, but there are setpoints for bringing additional chillers on line or removing chillers from operation. Those setpoints are found in Department Guide No. 40-09-004, paragraph 3.a.

Based on a review of chiller log information provided, it appears that the operators attempt to comply with this directive; however, a fairly substantial variation does exist. While some variation is probably attributable to the difficulty in maintaining the chilled water temperature over varying conditions, some is probably attributable to differences in operator preference and diligence. Since the efficiency of the chillers is greatly affected by the entering water temperature, any difference in operating preference can translate to operating at less than optimal conditions at least part of the time. Generally speaking, chillers operate more efficiently with higher entering water temperatures (which translate to higher evaporator temperatures for the same load condition). However, the ability of the cooling coils serviced by the chilled water to satisfy the cooling load of the conditional space (particularly the latent load) decreases as the temperature of the chilled water increases. Therefore, the most efficient chilled water return temperature (chiller entering water temperature) is the highest temperature at which the cooling load can be satisfied. It is assumed that this is the basis for the temperature guidelines established by Department Guide No. 40-09-004. What is not known is whether the Chiller Logs are reviewed for compliance with the guidelines. It is essential for these logs to be reviewed regularly and for feedback to be provided to the operators to help them to operate the chillers more efficiently.

4.4.2.2 Instrumentation and Measurement Equipment:

There is no indication in the preventive maintenance information provided for this study that the instrumentation and measurement is included or that it is subject to periodic recalibration. Since the operators are using this instrumentation to make their control decisions, inaccurate instrumentation could result in substantial impairment to the overall plant efficiency. For example, it is quite conceivable that, based on erroneous chilled water temperature information, an operator could bring an extra chiller on line long before it is needed with an obvious negative impact on plant efficiency. Consequently, it is recommended that all plant instrumentation and measurement equipment be included in a comprehensive, documented, and regularly scheduled calibration program.

4.5 Installation of New Burner Equipment

The design and condition of the burners on a boiler will determine the combustion efficiency of the equipment. The fuel must be mixed with the combustion air in order to assure complete combustion of the fuel. Since this technology is undergoing continuous improvement, some potential savings may be realized by upgrading from an older, less efficient system. However, as discussed below, it appears that the existing equipment is functioning well. As part of the investigation for this study, this issue was addressed with Cleaver-Brooks, a major boiler and burner manufacturer. The Cleaver-Brooks representative advised that, while a number of burner improvements have been made over the past twenty-five (25) years, significant efficiency increases have not resulted. Many of the improvements made relate to such things as enhanced turn-down capability and reduced NO_x emissions. Some efficiency improvement may have resulted from enhanced fuel/air mixing, but improvement figures have not been published. The Cleaver-Brooks representative doubted that a ten (10) year payback could be attained by replacing older burners with new technology and recommended that the older burners be retained as long as they continue to operate properly. Consequently, no burner testing has been conducted and no economic justification has been performed.

If major repairs become necessary, new equipment should be considered. An economic justification is not warranted because: 1) the existing burners are in good condition, 2) replacement burners are costly, 3) the efficiency gains would be small and costly to even determine, 4) an increase in burner efficiency will not translate to the same numerical increase in boiler efficiency, and 5) an economic analysis would necessarily be based on assumptions, which would introduce probable inaccuracies and uncertainties into the process, thus tainting the results.

4.5.1 Building 25330

During inspection, the burner equipment appeared to be in good condition, although internal access was not permitted to confirm this. Test data taken do not indicate problems with the burners. There are no recommendations for improving efficiency based on installation of new burner equipment.

4.5.2 Building 310

During inspection, the burner equipment appeared to be in good condition, although internal access was not permitted to confirm this. Test data taken do not indicate problems with the burners. Problems have been noted with smoking while burning oil, but these problems are likely attributable to incorrectly sized nozzles or incorrectly calibrated controls.

4.6 Economizers/Air Preheaters

An economizer is used to preheat water by utilizing lower energy boiler heat just prior to its discharge to the atmosphere. Air preheaters also use this low energy flue gas to heat the combustion air prior to its introduction into the furnace or burner area. This helps offset the energy required to heat the air to flame temperature.

4.6.1 Building 25330

Review of the boiler operating logs for Building 25330 reveals that for the majority of the year the boilers are operated at very low firing rates. At these low firing rates, the difference between the feedwater supply and flue gas temperatures is too little to extract a meaningful amount of heat from the flue gases. For about nine months of the year, the typical difference between flue gas temperature and supply feedwater temperatures varies between 75°F and 100°F. To capture a meaningful quantity of waste heat at these very low temperature differences would require prohibitively large and expensive economizers. No cost analysis has been performed due to the obvious physical impracticality of adding economizers under the existing operating conditions.

4.6.2 Building 310

Inspection of this boilerhouse revealed that the economizers with each boiler are working properly. Therefore, no recommendations can be made to improve the efficiency in the area of economizers.

4.7 Reduce Excess Air

Excess air is introduced to assure complete combustion of the fuel. Ideally, the minimum quantity of air for complete combustion would be introduced. However, due to the turbulent conditions at the burner, excess air is necessary to assure proper fuel and air mixing to support combustion. Excess air should be minimized to yield peak efficiency.

4.7.1 Building 25330

The savings due to the reduction of excess air were calculated based on the percent oxygen in the flue gas. The results indicated a total savings in FY 1990 of $2,535.

The percent oxygen in the flue gas at Plant 25330 in Fort Gordon was determined by testing and is listed in Table 1 below:

Table 1

% Oxygen

Capacity	25%	40%	50%	75%
Boiler 1	6.82	3.24	1.0	1.8
Boiler 2		4.2		3.2

The flue gas temperature was also measured and is listed in Table 2 below:

Table 2

Flue Gas Temp °F

Capacity	25%	40%	50%	75%
Boiler 1	392°F	421°F	428.55°F	489°F
Boiler 2		409.35°F		450°F

Table 3 was taken from "The Control of Boilers", page 72, 1986 by Sam Dukelow. It shows how combustion efficiency relates to percent oxygen and flue gas temperature. As seen, efficiency increases on decreasing % O_2 and decreasing flue gas temperature.

Table 3

Combustion Efficiency Chart - Gas

CO_2		12.1	11.5	11.0	10.4	9.8	9.2	8.7	8.1	7.5	6.9	6.4	5.8
Excess Air		0	4.5	9.5	15.1	21.3	28.3	36.2	45.0	55.6	67.8	82.2	99.3
Oxygen		0	1	2	3	4	5	6	7	8	9	10	11
	°F												
	300	85.6	85.4	85.2	85.0	84.7	84.5	84.2	83.9	83.5	83.0	82.4	81.7
	350	84.6	84.3	84.1	83.8	83.5	83.2	82.8	82.4	81.9	81.3	80.6	79.8
	400	83.5	83.2	82.9	82.6	82.2	81.8	81.4	80.9	80.3	79.6	78.8	77.8
	450	82.5	82.1	81.8	81.4	81.0	80.5	80.0	79.4	78.7	78.9	77.0	75.9
	500	81.4	81.0	80.6	80.2	79.7	79.1	78.6	77.9	77.1	76.2	75.2	73.9
	550	80.3	79.9	79.4	79.0	78.4	77.8	77.2	76.4	75.5	74.5	73.4	71.9
	600	79.2	78.7	78.2	77.7	77.1	76.4	75.7	74.9	73.9	72.8	71.5	69.9
	650	78.1	77.6	77.1	76.5	75.8	75.1	74.3	73.4	72.3	71.1	69.7	67.9
	700	77.0	76.5	75.9	75.3	74.5	73.7	72.9	71.9	70.7	69.4	67.8	65.9
	750	75.9	75.4	74.7	74.1	73.2	72.4	71.5	70.4	69.1	67.7	66.0	63.9
	800	74.8	74.2	73.5	72.8	71.9	71.0	70.0	68.8	67.5	65.9	64.1	61.9
	850	73.7	73.1	72.3	71.6	70.6	69.7	68.6	67.3	65.9	64.2	62.3	59.9
	Loss per Percent Combustibles												
		2.8	3.0	3.2	3.4	3.7	4.0	4.3	4.6	5.0	5.5	6.1	6.8

Using the O_2 and temperature measurements from the boiler tests, the combustion efficiencies were determined. These are presented in Table 4.

Table 4

Combustion Efficiencies

Capacity	25%	40%	50%	75%
Boiler 1	81.1	82	82.7	80.8
Boiler 2		82		81.3

The combustion efficiencies were extrapolated from the published data since the efficiencies calculated during testing were boiler efficiencies which included heat losses. Since the combustion efficiency does not include heat losses, and the heat losses were estimates, the combustion efficiency could not be calculated from the boiler efficiencies.

Table 5, taken from "The Control of Boilers" page 57, shows the recommended percent oxygen in flue gas for boilers using natural gas run at capacity.

Table 5

Excess Air Required at Full Capacity

Fuel	% Oxygen in Flue Gas	% Excess Air Min.
Natural Gas	1.5 to 3	7-15
Fuel Oil	0.6 to 3	3-16
Coal	4.0 to 6.5	25-40

Table 6 tabulates the reasonably achievable efficiency increases at capacity for the boilers in Building 25330.

Table 6

Reasonable Efficiency Improvements

Boiler 1	.5%
Boiler 2	.5%

Although the improved efficiency was based on the use of natural gas, we can assume that the improved efficiency will also occur when burning #2 oil.

The fuel consumption for Building 25330 in FY 1990 is listed in Table 7 below:

Table 7

FY 1990 Fuel Consumption

	Amount	BTU	%
Natural Gas	762,126 therms	7.621×10^{10}	95.77
Fuel Oil	24,674 gallons		4.23

From information provided by Ft. Gordon, natural gas prices are \$.51/therm and fuel oil prices are \$.99/gallon. As seen in Table 7, fuel consumption has been provided on a plant-wide basis; therefore, the cost savings must be calculated on the same basis. Cost savings are calculated as follows:

Building 25330 FY 1990

#2 Fuel Oil (density = 7.14 lb/gal)

$$24{,}674 \text{ gal} \times \frac{.81}{.815} = 24{,}523 \text{ gal}$$

24,674 gal - 24,523 gal = 151 gallons saved

151 gal x \$.99/gal = \$150

Natural Gas

$$762{,}126 \text{ therms} \times \frac{.81}{.815} = 757{,}450 \text{ therms}$$

762,126 - 757,450 = 4,676 Therms Saved

4,676 therms x \$.51/therms = \$2,385 Saved

Total Savings = \$2,385 + \$150 = \$2,535

As a workable interim measure, a portable combustion gas analyzer can be purchase for around $2,000. The cost estimate located in Appendix 3.3.4, Volume 2, provides additional information. This option provides a payback in less than a year.

The preferable long-term option is to include permanently mounted O_2 analysis/trim equipment as part of a complete upgrade of the boiler controls and recording equipment. The need for this upgrade has been addressed in previous paragraphs.

4.7.2 Building 310

The boilers at Building 310 have had both their Flame Safeguard and Combustion Control System Instrumentation replaced at the end of 1987. No further upgrade is required to allow most efficient operation of these boilers.

4.8 Loading Characteristics & Scheduling vs. Equipment Capacity

The efficiency of most heating and cooling equipment will decrease significantly as the load decreases. Therefore, proper matching of equipment operation to load is critical to the effective control of energy consumed.

4.8.1 Boilers

As can be seen by the charts in Section 4.7.1 Reduce Excess Air, boiler efficiency decreases with increasing excess air. It can also be seen that the boilers operate with lower excess air at high loads. Thus, boiler efficiency generally increases with increasing load.

To take advantage of this fact, when loads permit, the least number of boilers, operated at high capacity, should be used to meet the demand. It is more efficient to operate one boiler at high capacity than to operate two boilers at low capacity.

4.8.1.1 Building 25330:

No seasonal loading information is available for Building 25330 since the steam flow recorders in this plant are inoperative. It is clear, however, that these boilers are oversized for the available load throughout most of the year. This oversize condition apparently resulted from the fact that the boilers were originally sized to provide steam to absorption coolers, which have since been removed from service. In interviews with plant operating personnel, it was stated that it is sometimes difficult in the summertime to keep one boiler on the line due to insufficient load. Examination of the boiler logs provided revealed that operation with two boilers is extremely rare, even in the winter. Given the existing boiler equipment and load conditions, sequencing is not a major concern since the load seldom justifies the operation of more than one boiler at a time. In those rare situations where sufficient load appears to exist to warrant two burner operation, the sequencing decision is made based on steam pressure and HTW temperature since the steam flow recorders are broken.

4.8.1.2 Building 310:

It appears, from examination of the Daily Operations Logs and Facilities Engineering Operating Logs for Building 310, that it is common operating practice to operate two or three boilers at low capacity when one boiler operated at higher capacity could carry the load. During the period from October 1, 1989 through September 30, 1990, multiple boilers were operated on 151 days.

The department guide provides no written guidance on boiler sequencing, and after reviewing the logs, no sequencing pattern is apparent. From all appearances, the selection of the boiler combination to satisfy existent load conditions is left to operator discretion. As a result, there is great disparity in how the boilers are operated to satisfy the load. For example, on April 19, 1990, one boiler was operated to produce 203,000 pounds of steam; while on February 9, three boilers were operated to produce only 161,000 pounds of steam.

The three boilers in Building 310 are each rated at 16,400 pounds of steam per hour or 393,600 pounds per day. The heaviest heating load day for FY 1990 was December 23, 1989. On that day, 302,000 pounds of steam were produced by two boilers. During the coldest eight-hour period of the day an average of 13,361 pounds of steam were produced per hour. This equates to steady state steam production at 81% of a single boiler's capacity. While it is possible that load spikes may have necessitated the use of two boilers, it appears likely that even on the coldest day of the year, the load could have been carried by only one boiler.

Clearly, the boilers in Building 310 are not being sequenced as efficiently as possible. It is recommended that operating instructions be issued to require operation on only one boiler to at least 80% of its capacity (i.e. 13,120 PPH) before bringing a second boiler on line. This should be addressed in paragraph 3 of Department Guide No. 40-09-004.

4.8.2 Chillers

One of the primary inputs to the study of the chiller plant performance is the actual load which the plant is experiencing. In analyzing energy conservation opportunities, the profile of actual load versus time is of much greater value than mere block load information. Both the rate of change in load, and the period or frequency of change are key considerations in such applications as energy storage or load shifting.

Originally, this study contemplated the use of actual chiller loading information as the basis for constructing these profiles. Log sheets purportedly demonstrating actual loading data were obtained and profiles were developed. However, the resulting profiles do not appear reliable enough to make any determinations regarding project validity. The data are provided in eight-hour time periods. Therefore, the profile lacks sufficient detail to describe peaks or rates of change over the normal operating cycle. In addition, the unit description and conversion factors of the raw data appear suspect, for the corresponding calculated loads do not compare with the existing equipment. It has therefore been determined that the use of the existing load data would not be prudent in developing potential projects.

As part of the preliminary study, a Trane load analysis program has been utilized in order to develop a generic profile of a representative facility in this geographic location. ASHRAE guidance (1985 ASHRAE Fundamentals Handbook) has also been reviewed to model various loading conditions which could impact the generic study. However, this type of load analysis can only be used to develop initial project concept parameters for further study.

Without a more accurate load profile, we are presently unable to determine the normal loading condition over time of each chiller plant. However, our field observations suggest that the existing present load falls considerably short of the actual connected chiller capacity. Such an overcapacity situation would support an analysis for control of the chillers in multiples, where the best combination of numbers of chillers and load point sequences could significantly improve operating efficiency.

It must be emphasized that in order to establish the necessary load profile curves, it is absolutely imperative that accurate flow and temperature measuring and instrumentation devices be installed and that both temperature and flow data be recorded. It is recommended that each chiller plant have properly calibrated and appropriately placed pressure gauges for each zone CHWS line and recording thermometers for each zone CHWS and CHWR line. As discussed in paragraph 3.4, it is recommended that the EMCS be used to monitor system performance and to obtain and store performance data, including chilled water temperature and flow data. If that option cannot be pursued to EMCS memory or interface limitations, then, at a minimum, data must be collected manually at hourly intervals. Without that data, the load profile cannot be established. Further, without accurate flow and temperature information, there is no way to establish the instantaneous cooling load and, thus, be equipped with the necessary information to make intelligent chiller sequencing decisions.

At present, the chillers at Fort Gordon are sequenced manually at the operators discretion, based on existing observed load conditions. Many of the new chillers (approximately 10) have microprocessor control for individual chillers as well as manual limit controls.

In paragraph 3.4, a two-phase plan for interfacing chiller monitoring and control systems with the EMCS was presented. The ultimate goad of this plan is to allow for essentially all chiller data recording and control to be conducted from the EMCS control station. Because there is not reliable information available from which to establish a load profile and no information on the chiller operation and sequencing to satisfy the loads, there is no way to predict the actual savings from automatic chiller controls. However, from the observations previously made, it appears unlikely that the chiller plants are currently being operated as efficiently as possible. Given that and the existing capabilities of the Ft. Gordon EMCS, it appears that automating the chiller controls is worthy of serious consideration.

4.9 Variable Speed Circulation Pumps or Alternate Pumps Based on Seasonal Loading

In large water circulating systems, where pump horsepower requirements can exceed 50 horsepower, the use of two-way flow control valves and variable speed motor controls to maintain system pressure, may be advantageous if the load profiles reveal significant fluctuations. As the loads change at the terminal equipment, the valves close causing an increase in water pressure. This increase in pressure is detected and the pump speed is reduced, thereby saving motor horsepower.

4.9.1 Boilers

4.9.1.1 Building 25330:

No seasonal load profile information is available for this building and appropriate data are not available from which to build a load profile. The HTW is not metered for flow or flow rate information, and the steam flow recorders for the boilers have been inoperative for some time. The only available information upon which to base an analysis is fuel flow to the boilers. Consequently, an analysis was performed based on rough loading information derived from fuel flow to the boilers. It is important to recognize that the lack of available data required certain assumptions to be made in order to perform this analysis. While it is felt that the assumptions are reasonable given the plant conditions, the introduction of assumptions to the analysis increases the level of uncertainty in the results.

The calculations, contained in Appendix 3.2.4, Volume 2, predict a substantial annual energy savings with a fairly modest initial capital investment. The SIR for this viable energy conservation opportunity is 4.7. It is recommended for implementation.

4.9.1.2 Building 310:

The boilers in Building 310 provide saturated steam for heating and processes steam for the Hospital. Consequently, large HTW circulation pumps appropriate for variable speed drives are not existent in this plant. Therefore, no recommendations can be made for this boiler plant in regard to improving efficiency based on variable speed circulation pumps.

4.9.2 Chillers

Since insufficient data was available for the system beyond the chiller plant, a specific quantitative analysis could not be done for this ECO. However, a generic analysis was made utilizing a plant in the order of magnitude of those existing at Fort Gordon. This analysis indicated a definite ECIP at Fort Gordon.

An analysis was conducted to evaluate the economic feasibility of incorporating a variable speed pumping arrangement into the central plant chilled water distribution systems. Energy savings are achieved by the decrease in pump brake horsepower associated with reduced flow requirements at partial load conditions.

A "Generic" 1500 ton plant consisting of three 500 ton chillers was studied. A flow rate of 2.4 gpm per ton was used (3600 gpm) which corresponds to a 10 degree temperature difference between the chilled water supply and return. The head on the distribution pump was assumed to be 120 feet resulting in a nominal 150 horsepower motor.

Since no load information on the central plant is available, the Trane "Trace" output was used to generate a part load profile. In a variable flow arrangement, the supply and return temperature difference remains relatively constant with the flow varied in direct proportion to the imposed load. From the pump affinity laws, the pumping power will be reduced ideally by the cube of the flow. However, due to decreasing motor and pump efficiencies at reduced rpm and flow respectively, and minimum flow requirements of the chillers, a cubic decrease in horsepower requirements is not achieved.

For the constant flow arrangement a single circulating pump distributes chilled water to the load. Since investigation of the actual terminal equipment is beyond the scope of work, a typical three-way mixing valve with a valved bypass arrangement is assumed. The chillers are piped in a parallel configuration with no provisions made for automatic control of the chillers shutoff valves. A schematic of this scheme is presented in Sketch #1 on page one of Appendix 4.1.3, Volume 2, for the chillers.

Manufacturer's data were used to approximate the typical full load pump and motor efficiencies. Since the base distribution systems are rather large, a pump head of 120 feet was assumed. This value is typical for several of the pumps at the central plants.

The energy plants produce chilled water all year resulting in 8,760 operating hours per year. With the above information, the annual kilowatt hours associated with the pump operation are calculated based upon constant flow. This information is presented in page two of Appendix 4.1.3, Volume 2.

With a variable flow system, provisions must be made to ensure that minimum flow is maintained through the chillers. This is generally accomplished by one of two methods. The first approach is to reconfigure the system into a primary/secondary pumping arrangement. This requires that dedicated circulating pumps be provided for each chiller, which are interlocked to run when the chiller is operating, and the piping is configured into a primary loop. The distribution pump draws water off of the primary loop to serve the load.

The second method is to provide motorized valves such that at part load (part flow) the flow through an inactive chiller can be diverted to the other machines. Since the flow through the active chiller(s) is varying, control of the leaving chilled water temperature is more difficult. Due to an increased complexity of controls associated with this scheme the first method was adopted for the purposes of this analysis. A schematic of the revised system layout is shown in Sketch #2 on page three of the Appendix 4.1.3, Volume 2.

The primary pumps are sized for the chilled water flow through each machine with a head equal to the pressure drop through the chiller and primary loop piping. This head is estimated to be approximately 20 feet which reduces the head seen by the secondary pump to 100 feet (120-20). The number of primary pumps operating coincides with the number of chillers operating and depends upon the partial load on the central plant. Since three equal tonnage chillers have been assumed, one pump/chiller operates 33% load, two operate up to 66% load, and three above 66%. The energy consumed by these primary pumps must be accounted for to provide an accurate analysis.

The secondary pump head at design flow is used to calculate the head imposed by the system at partial loads (gpm) by using the pump affinity laws. Since the efficiency of a pump varies with speed, (gpm) an approximation of the pump efficiency at various flows was made by interpolating between typical full and part-load efficiencies. The pump brake horsepower at each load condition can then be calculated by using the part-load head, gpm and pump efficiency values.

Once the pump brake horsepower is calculated, the energy consumption in kilowatts may be determined by accounting for motor and drive efficiencies. The efficiency of a typical NEMA "B" four-pole nominal, 1800 rpm electric motor decreases at reduced speed. An interpolation of manufacturer's data for a typical motor was performed to determine the motor efficiency at each part-load condition. The drive efficiency for a variable torque, adjustable frequency, type motor controller remains relatively constant at various frequencies. Therefore, an average efficiency of 92% was used for the motor controller.

Using the average monthly load at Fort Gordon and the above information, calculations were performed to determine the energy usage of the secondary chilled water pump using the variable speed drives. A summary of the formulas and efficiencies used for these calculations is contained on page four of Appendix 4.1.3, Volume 2. These calculations were made and are presented in tabular form on pages five and six of Appendix 4.1.3, Volume 2.

The energy usage of the two schemes is summarized for each site on page six of Appendix 4.1.3, Volume 2. Based upon these calculations, incorporation of a variable speed chilled water distribution system at Fort Gordon will save 637,260 kwh per year. At an average electrical consumption cost of $.055 per KWH (including all rate schedule impacts), the average savings per year would be $35,050 for the generic study case.

An estimate of the anticipated first costs associated with implementation of a variable speed pumping scheme was made. A copy of the estimate is contained on page seven of Appendix 4.1.3, Volume 2. The data were used to complete a Life Cycle Cost Analysis Summary Sheet of the Energy Conservation Investment Program (ECIP).

The variable speed pumping at Fort Gordon has a Savings Investment Ratio (SIR) of 4.6, which indicates implementation of this Energy Conservation Opportunity (ECO) is economically feasible. The Life-Cycle Cost Analysis Summary Sheets are contained on pages eight through twelve of Appendix 4.1.3, Volume 2, with miscellaneous calculations found on pages thirteen and fourteen of Appendix 4.1.3, Volume 2.

Specific calculations for the central plants at Fort Gordon were not performed due to a lack of information regarding the part-load profile of each plant. From the generic analysis, those central plants characterized by relatively high horsepower pumps, which operate for a significant portion of the year at part-load, variable speed pumping is an economically viable energy conservation opportunity.

4.10 Voltage Regulators on Large Electrical Equipment

Where the voltage supply from the utility grid fluctuates or where the loads on the various phases of the electric system are unbalanced, the application of voltage regulators may improve performance. This was discussed with the base utility representative, and it was determined that this was not required at this facility.

Based on our meeting with the Corps on December 12, 1985, there was agreement between the Corps and the A/E that the application of voltage regulation at these facilities is not feasible.

4.11 Reductions in Make-Up Water Quantities

The make-up water required for boilers, chillers and cooling towers can be significant. The actual water consumption is one consideration, but the cost of chemicals required to treat this water usually overshadows the cost of water. The cost of lost energy is also extremely high.

4.11.1 Building 25330

In an interview with boiler operators on March 8, 1988, it was noted that make-up water was reported to be 6,000 gallons per day. During the October 1990 site visit, the operators reported 7,000 - 9,000 gallons per day HTW make-up and 5,000-9,000 gallons per day chilled water make-up. Examination of the Daily Operation Logs for this building reveals HTW make-up quantities in the approximate range of 2,000-5,000 gallons per day normally, but with a few aberrant days, much higher rates indicated significant leaks. Chilled water make-up varied from about 1,500-6,000 gallons per day normally, but there were a number of very high days (ie: over 30,000 gallons per day), indicating very significant leaks. No leaks were noted within the boilerhouse during inspection, so the make-up water must be the result of leaks in the field, which is out of the scope of this report. Therefore, it is recommended that the distribution system be inspected for obvious system leakage and appropriate repairs made.

4.11.2 Building 310

In an interview with boiler operators on March 8, 1988, it was noted that make-up water was reported to be 6,000 gallons per day. Review of the Plant Operating Logs reveals that boiler make-up averages were (fairly consistently) between 4,000 and 5,000 gallons per day (33,360 lb/day - 41,700 lb/day). This amounts to about 25% of the total load (approximately 150,000 lb/day average). This represents a significant steam distribution system loss worthy of further investigation by Fort Gordon.

Chilled water leakage at Building 310 and its' serviced buildings is insignificant.

4.12 Evaluation of Electric vs. Steam/HTW/Absorption Chillers

Over the past twenty years, the increasing cost of electricity has made alternate energy sources practical. Where steam or hot water is readily available, an absorption chiller system may be feasible. The major deterrent to this type of system is the increased maintenance costs associated with chiller operation. Historically, these maintenance costs have been high enough to make absorption chillers impractical except in areas where electrical energy costs are very high.

Recent studies have shown that unless the fuel cost to produce steam or HTW is nearly zero, absorption machines are not cost effective. With initial cost and maintenance cost being significantly higher for absorption machines vs. electric, operating cost would have to be significantly lower in order to make absorption equipment life-cycle cost effective.

The current (FY 1991) energy unit costs at Fort Gordon are:

#2 Fuel Oil	-	\$1.03 per gallon	(1)
Natural Gas	-	\$0.51 per therm	(2)
Electricity	-	\$0.055 per KWH	(3)

Notes: (1) Per Curt Oglesby
(2) From Oct. 1990 Invoice
(3) Per Curt Oglesby. Estimate includes all schedule impacts, including demand.

As shown by the following example, with a new chiller operating at 0.6 kw per ton (centrifugal) and an electric rate of \$.055 per kw (including demand charges), operating (energy) cost is about \$.033 per ton of cooling capacity.

A comparable absorption machine utilizing steam produced by an 80% efficiency boiler burning oil at \$1.03 per gallon would cost about \$.155 per ton. Even burning natural gas at \$.51 per therm

(100,000) absorption would be more than electric cost for energy at $1.07 per ton. (See following calculation.)

A detailed analysis could be done on this particular ECO; however, our experience and apparently the experience at the Corps of Engineers (since all existing absorption machines have been replaced over the last 3± years) would indicate that such a detailed analysis is unwarranted. Clearly, if it costs more to produce absorption cooling than electric chilling without even considering the additional capital investment required, then such an analysis would not result in an ECIP even approaching 1.

Electric vs. Steam/HTW/Absorption Table

1. Centrifugal Chiller @ 0.6 kw per ton of output

   Electric Rate @ 55¢ per kw x .6 $\frac{\text{kw}}{\text{ton}}$ = 3.3¢ per ton cooling

2. Absorption Machine

   Requires per manufacturers data 18.7 lb steam/ton-hr

   18.7 lbs. steam x 900 $\frac{\text{BTU}}{\text{lb}}$ = 16,830 BTU/Ton

   w/80% efficiency boiler = 21,000 BTU of fuel input per ton cooling

   a) Oil @ 140,000 BTU/Gal @ $1.03 per gallon =

   $$\frac{\text{21,000 BTU Fuel}}{\text{Ton Cooling}} \times \frac{\text{Gal Fuel}}{\text{140,000 BTU Fuel}} \times \frac{103¢}{\text{In Gal Fuel}} =$$

   <u>15.5¢ PER TON</u> Cooling

   b) Natural Gas @ 51¢ per Therm (100,000)

   $$\frac{\text{21,000 BTU}}{\text{Ton Cooling}} \times \frac{\text{Therm}}{\text{100,000 BTU}} \times \frac{51¢}{\text{Therm}} =$$

   <u>10.7¢ PER TON</u> Cooling

ENERGY COST OF ELECTRIC VS. ABSORPTION INDICATES <u>SIGNIFICANT</u> SAVINGS WITH ELECTRIC.

4.13 Control Systems to Operate Chillers at Energy Efficient Operating Conditions

The design of a centrifugal chiller causes the most efficient operating point to occur at approximately 70 to 80 percent of full load. Also, no two machines are going to operate at the same efficiency throughout their load range. Therefore, the units should be utilized in such a way that overall energy consumption is minimized by operating the most efficient units at their most efficient capacity.

As addressed in Section 3.3, the chillers are currently sequenced manually based solely on chiller water return temperatures. There is no written sequencing plan based on current load conditions and chiller efficiency, and no apparent attempt is made to operate the chillers in the most efficient manner possible.

Insufficient data currently exists from which to develop a detailed sequencing plan. As previously addressed, it is recommended that the existing EMCS be expanded and interfaced to the chiller systems in a passive mode; i.e., data collection only. From the resulting data base, a detailed and meaningful chiller sequencing plan could be developed that would result in significant cooling energy savings.

It is possible, however, based on the chiller performance data presented in Section 2.2, to make some general observations regarding those chillers that were tested under this study. Those observations are presented in the following paragraphs.

4.13.1 Building 25910

The chiller EER ratings for this building are as shown in the following table.

Operating Points

Chiller	100%	80%	65%	50%
1	---- Not Tested ----			
2	22.03	22.07	21.85	18.8
3	14.99	16.06	16.67	17.39
4A	12.06	11.77	10.80	8.71
4B	15.53	15.27	13.74	15.29
5	---- Not Tested ----			
6	---- Not Tested ----			
7	---- Not Tested ----			

As can be seen, four of the eight chillers in this building were not included in the project Scope of Work. The four that were tested should be sequenced in the following order: Chiller 2, Chiller 3, Chiller 4B and Chiller 4A.

Note that the chiller efficiencies generally peak at 80% - 100% of maximum capacity.

4.13.2 Building 25330

The chiller EER ratings for Building 25330 are as shown in the following table.

Operating Points

Chiller	100%	80%	65%	50%
1	22.57	23.34	15.55	7.52
2	22.23	21.85	12.52	9.70
3	---- Not Tested ----			
4	---- Not Tested ----			

As can be seen from this table, only two of the four chillers in this building were included in the Scope of Work. They can be sequenced in any fashion since the efficiencies are closely matched. It should be noted, however, that the efficiencies drop off dramatically below the 80% operating point. Consequently, the chillers should be operated at or above this point.

4.14 Use of Heavy Oils for Plants with Light Oil Burners

The cost of heavy oils is usually less than the cost of the lighter grade fuel oils, thereby creating a potential reduction in energy costs. This potential savings will be offset to some degree by increases in maintenance costs and equipment expenditures required for proper handling and burning of the heavy fuels.

4.14.1 Building 25330

The fuel consumption for the boilers in Building 25330 during Fiscal Year 1990 is summarized in the table below.

FY 1990 Fuel Consumption - Bldg. 25330

	Amount	BTU's	%
Natural Gas	762,126 therms	7.621×10^{10}	95.77
#2 Fuel Oil	24,674 gallons	3.423×10^{9}	4.23

As shown by the calculations in the cost estimate and Life-Cycle Cost Analysis contained in Appendix 3.2.5, Volume 2, this project marginally qualifies as an economically viable ECO with Savings to Investment Ratio (SIR) of 1.0 based on the Fiscal Year 1990 fuel consumption data.

4.14.2 Building 310

The fuel consumption for the boilers in Building 310 during Fiscal Year 1990 is summarized in the table below.

FY 1990 Fuel Consumption - Bldg. 25330

	Amount	BTU's	%
Natural Gas	7.321×10^{5} therms	7.321×10^{10}	97.0
#2 Fuel Oil	16,113 gallons	2.235×10^{9}	3.0

As shown by the calculations in the cost estimate and Life-Cycle Cost Analysis contained in Appendices 3.2.4 and 3.2.5, Volume 2, this project has a Savings to Investment Ratio (SIR) of 0.6 and, consequently, does not qualify as an economically viable ECO. From the calculations for Building 25330, it can be seen that approximately 25,000 gallons per year would have to be burned to make the project economically viable.

4.15 Blowdown Control

4.15.1 Building 25330

No blowdown was noted during inspection of this boilerhouse, and no controls are required for continuous blowdown. No recommendations are made for increasing efficiency based on blowdown control.

4.15.2 Building 310

No blowdown was noted during inspection of this boilerhouse, and no controls are required for continuous blowdown. No recommendations are made for increasing efficiency based on blowdown control.

4.16 Condenser/Cooling Tower Water Treatment

Wherever water is heated, cooled, and oxygenated, the formation of scale and algae will occur. The application of chemicals and continuous monitoring is required to control the effects of these items. Fouling of the chiller's condenser tubes will cause the system efficiency to decrease. The corrosion of system components will require their replacement much sooner than normal.

Water treatment of the condenser water was observed to be installed and operating at all installations. The basic method utilized was a timed (pulse) meter which injected chemicals into the system. Chemicals were stored in drums for each chiller/tower combination and separate feeder systems were installed on each.

Our investigation indicated acceptable levels of algae growth in the towers, minimal scaling in the tower basins, no foaming in the basins, minimal corrosion of tower components and acceptable pressure drops through chiller condensers.

While the system installed is apparently working satisfactorily, no readings were taken or available regarding tower bleed rate. Installation of an automatic measurement (conductance) of dissolved solids and automatic bleed could result in water make-up savings.

A visual inspection indicated that the water treatment program appears to be generally successful, except for some algae build-up in Building 310 cooling towers. However, as previously noted, the cooling tower conditions, and particularly the cooling tower media conditions, are generally fair to poor. Since the largest inefficiencies in cooling tower performance result from deteriorated fill material, fine tuning water treatment practices at this stage would offer little improvement. The first priority must be to repair/replace the towers such that proper operation is attained.

A quantitative analysis (or ECIP) is very difficult for the water treatment since it would have to relate to the system as presently installed and its effect which is almost impossible to determine. An analysis of bleed rate and water make-up reduction could be done and quantified; however, the data to perform that analysis are not currently available. If the previously made recommendations concerning instrumentation and interface with the EMCS are implemented, then a data base can be developed such that a full analysis can be made in the future.

4.17 Deactivation of Facilities by Satelliting of Central Plants

In a large, campus-style distribution system, the energy consumed by pumping chilled or hot water can be significant. By satelliting smaller systems throughout the distribution system, pumping requirements are reduced, but overall system efficiency may not improve due to the use of smaller, less efficient cooling or heating equipment.

The decision to decentralize a portion or all of a system load is based on the profile of the loads served. For example, if a chapel, used only for weekend services, is supported by a main chiller plant, there would be obvious potential for savings through decentralizing that load. However, this decision would be based on the actual profile of that individual load as compared with the total system load.

Actual load profiles are essential to complete an analysis of this issue. Current load data are insufficient to provide reasonably accurate profiles of the load. (See 4.8.2.)

4.18 Calculations to Justify Outdoor Reset Temperature Control

In facilities where a significant percentage of the thermal load is caused by outside ambient temperature and humidity conditions, a system which monitors these conditions and adjusts system set points can result in substantial energy reductions. The most widely used of these systems either adjust chill water set points or modulate the percentage of outside air through the air handlers.

Chill water control systems typically take advantage of outside reductions in latent heat. Chill water set points are usually established to meet humidity control requirements. Air handler cooling coil sizing is based on the chill water set point and the desired leaving air temperature.

When outside humidity conditions are low, the total heat in the air stream is reduced. The level of reduction is based upon the percentage of outside air introduced through either fresh air ventilation or infiltration. The reduced total heat allows an increase in chill water temperature while maintaining leaving air temperature control.

This type of outside ambient control has potential for single facility systems in which outside air is a significant portion of the load. For example, retail sales areas which have significant infiltration through door ways and connected exterior sales areas can offer substantial energy reductions through this approach.

The second method of outside ambient control is commonly referred to as enthalpy control. Enthalpy control systems compare the total heat (latent and sensible) of the outside air with that of the return air.

When outside air total heat is less than the return air stream, dampers increase the level of outside air, exhausting a corresponding amount of return air. The percentage of return air used is usually dependent upon nominal humidity requirements.

In a central chiller plant system serving many various facilities, the use of chill water reset is impractical. Since outside ambient conditions have varying impacts on each of the building served, it would be poor practice to adjust chill water design temperatures without analyzing specific facility load data. Based on the typical military use facilities, and the limited use of the chiller plant during low outside ambient conditions (the chiller plant off season), a significant potential for energy savings would not be anticipated.

The enthalpy systems are air-side oriented, and are therefore outside the scope of this study. However, again, based on the limited chiller use during low outside ambient conditions, a substantial energy savings is doubtful.

The lack of specific information on the outside ambient impact on each facility precludes calculations on actual energy savings.

4.19 Variable or Two-Speed Cooling Tower Fan

The efficiency of the chiller will improve as cooler condenser water is delivered. However, the lower limit suggested by most manufacturers is 70 degrees. As this lower limit is approached, the cooling tower fan operation can be modified to save on fan energy consumption.

A generic study is included herein and based on this study such implementation may be feasible for an ECIP.

Energy is consumed in driving the fan, or fans, necessary to achieve proper air movement through a cooling tower. The quantity of air flow through a tower necessary to maintain desired leaving water temperatures will vary with changing loads and ambient conditions. The goal of this energy conservation measure is to reduce the fan energy consumption while maintaining a constant leaving water temperature.

The obvious goal of this energy conservation measure (ECM) would be to reduce the fan energy consumption to a minimum. Due to the numerous variables which affect cooling tower and chiller operation, this analysis is very complex. The changes in ambient wet-bulb temperature, dry-bulb temperature, systems load, air density and water flow rate all affect the tower performance. In order to analyze this ECM several of these factors will need to be considered constant.

One major consideration must be that the efficiency of the centrifugal chiller will improve as the condenser water temperature decreases. Therefore, the low-end temperature at which the system is controlled must be carefully selected. Eighty-five degrees is normally selected for the high load inlet temperature to the chiller. As the ambient temperatures and loads decrease, colder water is possible from the tower. On average, a one-percent reduction in energy consumption can be expected with a one-degree reduction in condenser water temperature. However, this is limited to low temperature of approximately 65°F; based upon a design condensing temperature of 85°F, a potential reduction approaching 20% of design energy consumption can be achieved by lowering the condenser water to 65°F when ambient conditions and systems load permits.

The locale being studied will yield ambient conditions which would allow the water temperature to drop below 65°F if permitted to do so. It is during these periods of time when variable-speed fan control would be feasible. Since the existing cooling towers are already utilizing two speed motors, the overall plant energy savings possible from a variable-speed fan installation would be minimal.

The potential for energy savings by utilizing a variable-speed fan control, although small, does exist. However, recent studies on the existing towers demonstrated that this project would not offer a significant cost savings due to base loading conditions. Instead, efforts should focus on:

1. repairing/replacing cooling media in the towers, and
2. repiping towers to manifold distribution system as shown in paragraph 3.3.5.

Once these two activities are complete, the control system should bring on individual cooling tower cells to meet the demand placed on the manifold. The estimated base load is greater than the smallest single-tower cell, even under low ambient conditions. The manifold system would, in effect, create a staged variable capacity condenser water system, roughly equivalent to variable speed fans. It would also offer redundance and ease of operation.

Based on other recommended actions, the installation of variable-speed cooling tower fans is not recommended.

4.20 Free Cooling Cycles

In certain locations, it may be possible to cool the chilled water by using the cold condenser water when outdoor air temperatures are low enough. Rather than using the refrigerant/compressor cycle to exchange heat from the buildings to outdoors, this cycle is bypassed directly to the cooling towers.

An analysis was conducted to evaluate the economic feasibility of incorporating a free cooling arrangement into the central plant chilled water systems. Energy savings are achieved by the avoidance of chiller compressor operation associated with operation of the cooling tower to produce chilled water at low-ambient temperature and partial-load conditions.

A "Generic" 1500 ton plant consisting of three 500 ton chillers was studied. A flow rate of 2.4 gpm per ton was used (3600 gpm) which corresponds to a 10° temperature difference between the chilled water supply and return. The condenser water system is comprised of three single-cell cooling towers, each with a 25 horsepower fan motor. This tower selection was made from manufacturer's data, assuming the tower capacity is 30% greater than the chiller capacity, and using a design wet-bulb temperatures of 79°, a 7° approach, and a 10° range.

Since no reliable information on the actual central plant loading is available, the Trane "Trace" output was used to generate a part-load profile. The chillers are piped in a parallel configuration with no provisions made for automatic control of the chillers shutoff valves. A schematic of this scheme is presented on Sketch #1 on page 15 of Appendix 4.1.3, Volume 2, for the chillers.

To incorporate a free cooling operational scheme, plate-type heat exchangers are used to transfer heat between the condenser and chilled water loops. Two heat exchangers are required to satisfy the maximum wintertime, part-load conditions of 979 tons, since the cooling towers have a nominal capacity of 650 tons each. A diagram of this arrangement is contained in Sketch #2 on page 16 of Appendix 4.1.3, Volume 2.

A determination of the ambient wet-bulb temperature that will produce sufficiently cold leaving tower water must be made to ascertain the hours of operation during which free cooling is available. A 55° wintertime supply chilled-water temperature was assumed as per ASHRAE 1983 Equipment Volume, page 21.9. From manufacturers' data on heat exchangers, it was determined a 5° approach between entering and leaving water could reasonably be attained. Due to mixing associated with the three-chiller, parallel configuration, the heat exchangers must produce 53° water. Therefore, with a 5° approach, the cooling towers must be capable of producing 48° leaving water temperature.

A typical cooling tower performance curve at varying ambient wet-bulb temperatures was obtained from Chapter 20 of the ASHRAE 1988 Equipment Volume. Although the tower range will vary in proportion to the imposed load, an average range based upon the average load was calculated. With the leaving tower water temperature and condenser water range determined, an ambient wet-bulb temperature of 36° was obtained from the tower performance curve. From the cooling tower performance curve, it is apparent that as the tower range is reduced, the ambient wet-bulb temperature, at which free cooling tower is available, increases. To account for the varying cooling tower range, an ambient wet-bulb temperature of 38° was used for the temperature at which free cooling is available. Detailed calculations are contained on page 17 of Appendix 4.1.3, Volume 2.

To find the hours when the wet-bulb temperature is below 38°, weather data for each Fort were obtained from "Engineering Weather Data", TM-785. Since this publication divides each month into three time periods of observation, the average load coinciding with these time periods was determined from the Trace output. The data were used to calculate the ton-hours of chiller operation that could be avoided utilizing free cooling.

To evaluate the energy savings the chiller efficiency must be accounted for. For this generic study, a full-load efficiency of 0.70 kw per ton was used with part-load efficiencies determined from a typical centrifugal chiller unloading curve at a reduced condenser water temperature of 65°. The formulas used to perform these calculations are summarized on page twenty-three of Appendix 4.1.3, Volume 2, with the weather data and load profiles contained on pages nine through twelve of the Appendix. The results of the calculations are presented on page fourteen of Appendix 4.1.3, Volume 2.

To determine the net energy savings, the increased cooling tower fan energy consumption associated with free cooling must be accounted for. The periods at which the potential for free cooling exist are characterized by low ambient wet-bulb temperatures. Therefore, the existing two-speed cooling towers would be operating a low speed if the chillers were being used to handle the load. To produce free cooling however, the tower's fan would have to operate on high speed, thus increasing the tower power consumption. The chiller energy savings is reduced slightly by this increased tower energy consumption. The formulas used to determine the impact of the increased tower energy consumption are presented on page eighteen of Appendix 4.1.3, Volume 2.

The net energy saving of the free cooling schemes is summarized on page nineteen of Appendix 4.1.3, Volume 2. Based upon these calculations, incorporation of a free cooling chilled water arrangement system at Fort Gordon will save 269,852 kwh per year. The energy savings at Fort Bragg are less since the chillers are shutdown during the winter months when the low, ambient temperatures required for free cooling are available.

An estimate of the anticipated first costs associated with implementation of a variable-speed pumping scheme was made. A copy of the estimate is contained on page twenty of Appendix 4.1.3, Volume 2. The data were used to complete a Life-Cycle Cost Analysis Summary Sheet of the Energy Conservation Investment Program (ECIP).

The use of free cooling at Fort Gordon has a Savings Investment Ratio (SIR) of 0.79, which indicates implementation of this Energy Conservation Opportunity (ECO) is not economically feasible. The SIR for Fort Bragg was calculated to be 0.051, and therefore, implementation at this site is also not economically justifiable. The Life-Cycle Cost Analysis Summary Sheet is contained on page 18 twenty-one of Appendix 4.1.3, Volume 2, with miscellaneous calculations found on page twenty-two of the Appendix.

Based upon this analysis, incorporation of a free-cooling arrangement is not economically feasible at Fort Gordon. The Savings Investment Ratio was less than one, indicating that this ECO is not viable. Therefore, we recommend that the current arrangement be retained and further investigation of the potential for free cooling be directed towards air-side economizers for the terminal air-handling equipment.

4.21 Addition of Steam Accumulators

This item was deleted from consideration in a meeting held in Atlanta, Georgia on October 9, 1985.

4.22 Steam Driven Auxiliaries vs. Electric Drives

The energy consumed by system auxiliaries, particularly pumps and compressors, can be significant for large central energy plants. All feasible energy sources should be considered including purchased electricity and steam produced on site.

The boiler plants under consideration for this study, Buildings 310 and 25330, both contain moderately small boilers producing saturated steam. For the purposes of this analysis, Building 310 will be used as an example; however, due to the plant similarities, the conclusions also apply to Building 25330.

Building 310 contains three small (16,400 PPH) boilers operating in balanced draft condition. Its primary auxiliaries are the boiler feedwater pumps, induced draft (I.D.) fan and forced draft (F.D.) blowers. Because of the relatively small size of the plant, the auxiliary drivers are also small. The feedwater pump motors are 15 horsepower each, and the I.D. and F.D. fans are 10 horsepower each.

Current practice is to limit steam turbine driven auxiliaries to large (over 500 MW) steam electric plants. (Ref.: Babcock & Wilcox, Steam/Its Generation and Use.) Note that the boilers in Building 310 are approximately 100 times smaller than this minimum practical standard for using steam driven auxiliaries in lieu of the standard electric-driven auxiliaries.

The driving force behind this practical limit is the high cost of steam turbine equipment drivers and the associated piping and control equipment. Substantial energy savings are required to offset the large initial capital investment, and this can only be accomplished when the auxiliaries are large power consumers. This is clearly not the case in Building 310.

As shown by the calculations in Appendix 3.3.4, Volume 2, projected energy savings from using steam driven auxiliaries would be on the order of $2,000 per year.

With an estimated initial capital cost of over $100,000, this clearly does not represent a viable Energy Conservation opportunity.

As previously noted, by analogy this conclusion applies also to Building 25330.

4.23 Variable Speed Induced Draft Fans and Forced Draft Blowers

The method selected for controlling the quantity of air entering the boiler can affect the plant efficiency. In the usual application, the fans/blowers are operated at constant speed, and the air flow is controlled by variable inlet vanes or dampers. Since this method forces the fans to operate in an inefficient portion of the curve for much of the time, it is generally not considered to be an energy efficient method of air volume control.

By contrast, varying the air volume, by controlling fan speed, with variable-frequency drives operating at speeds and voltages matched to system conditions results in more efficient fan operation and reduced energy costs.

4.23.1 Building 25330

From the calculations included in Appendix 3.2.4, Volume 2, it can be seen that installing variable-frequency drives on the 15 horsepower forced-draft blowers would result in savings of about $3,600 per year in electricity costs with an estimated capital expenditure of about $20,000. This project qualifies as a viable ECO with a SIR of 1.6.

4.23.2 Building 310

Equipping the 10 horsepower induced-draft fans and forced-draft blowers on the three (3) boilers in Building 310 with variable speed drives would save about $4,800 per year with an initial investment of about $27,000.

As with Building 310, this project qualifies as a viable ECO with a SIR of 1.6. The calculations are included in Appendix 3.3.4, Volume 2.

4.24 Fuel Quality Changes

The type of fuel used in a boiler will affect the operating costs for the plant, the efficiency of the plant, and the maintenance costs of the plant. A balance must be reached between the savings of a lower grade fuel and the reduction in burner efficiency and added maintenance costs.

4.24.1 Building 25330

The fuels used in this building are natural gas as the primary fuel and fuel oil #2 as the secondary fuel. Samples of both fuels were taken from boiler number one and analyzed. The gas samples compare favorably with the standard ranges. Some slight variations in the natural gas analysis are expected, since the standard data is a compilation of average analyses obtained from the operating utility company(s) supplying the city. The gas supply may vary considerably from these data-especially when more than one pipeline supplies the city. When new supplies are received from other sources, the analysis may also change. The City of Atlanta was used to compare with the Fort Gordon samples.

No quality changes can be made on natural gas, the primary fuel, to increase efficiency. Using a heavier oil in place of number 2 fuel is addressed in Section 5.14.1, Use of Heavy Oils for Plants with Light Oil Burners.

4.24.2 Building 310

The fuels used in this building are natural gas as the primary fuel and fuel oil #2 as the secondary oil. Samples of both fuels were taken from boiler number one and analyzed. The gas samples compare favorably with the standard ranges. Some slight variations in the natural gas analysis are expected since the standard data is a compilation of average analyses obtained from the operation utility company (s) supplying the City. The gas supply may vary considerably from this data -especially when more than one pipeline supplies the City. When new supplies are received from other sources, the analysis may also change. The City of Atlanta was used to compare with the Fort Gordon samples.

No quality changes can be made on natural gas, the primary fuel, to increase efficiency. Using a heavier oil in place of the number 2 fuel was addressed in section 4.14.2 of this report.

4.25 Instruments and Controls to Facilitate Efficient Operations

For a chiller or boiler plant to operate efficiently, it must be able to respond to changes in system load. In most cases, this means a relatively small change in temperature could signal a reduction in system load. The plant operator and his controls must be able to detect this change and respond accordingly.

Please refer to Sections 3.2 and 3.3 of this report for a thorough discussion and specific recommendations relative to boiler and chiller systems' instrumentation and control upgrades and operational practices.

4.26 Interconnection of Plants 1 & 2

The larger the system being served by a given central plant, the greater the potential for load diversity. Also, a larger central plant with multiple pieces of equipment could be able to handle certain load conditions more efficiently by operating its most efficient units.

Both central plants 1 and 2 at Fort Gordon are oversized for the loads they serve. This is true year-round but is particularly true in the summer time when the HTW is used only to produce domestic hot water. From examination of the boiler operating logs for both plants, it is clear that during the Fiscal Year 1990, there was no period of time when the boilers in Building 25910 (Central Plant 1) could not have adequately served the load serviced by both plants.

From interviews with Fort Gordon personnel, it is understood that consideration has been given to connecting the two plants directly across the parade field and allowing the load to be serviced by either Central Plant 1 or Central Plant 2. This is probably not a practical solution for a number of reasons:

1. The existing line sizes on both sides of the field would be inadequate to carry the necessary flow. Consequently, these lines, which are in highly congested areas and which are integral to the HTW distribution system to many buildings, would have to be replaced. This would be extremely disruptive.

2. It is not clear that the boilers in Central Plant 2 could carry the full load year round. It is not possible to positively determine the adequacy of Central Plant 2 for this purpose since the steam flow recorders are inoperative, and there are no HTW flow measurement devices.

3. Balancing flows in this arrangement would be difficult to impossible.

As an alternative, it is suggested that consideration be given to connecting the plants as shown in figure 1 on the following page. In this configuration, the boilers in Central Plant 1 would carry the heating load currently carried by both plants year round. While this alternative is not inexpensive (it is estimated to cost over $1.5 million), it offers the following advantages:

1. It avoids the necessary disruption of replacing integral parts of the HTW distribution system in congested areas.

2. It allows the boilers in Central Plant 2 to be permanently shut down, thus avoiding current operating and maintenance costs.

3. It allows the avoidance of necessary repair/upgrade costs to Central Plant 2, such as replacing the boiler control systems.

4. Though efficiency data is not available for the boilers in Central Plant 1 (they were excluded from the scope of this study), they should operate more efficiently than those in Central Plant 2 because they are equipped with an economizer system and state-of-the-art digital controls.

A cost estimate has been prepared for this ECO and is included in Appendix 3.2.4, Volume 2. However, an energy savings analysis could not be performed due to the lack of performance data for Central Plant 1 and steam flow information for Central Plant 2. Consequently, a Life-Cycle Analysis Summary could not be completed.

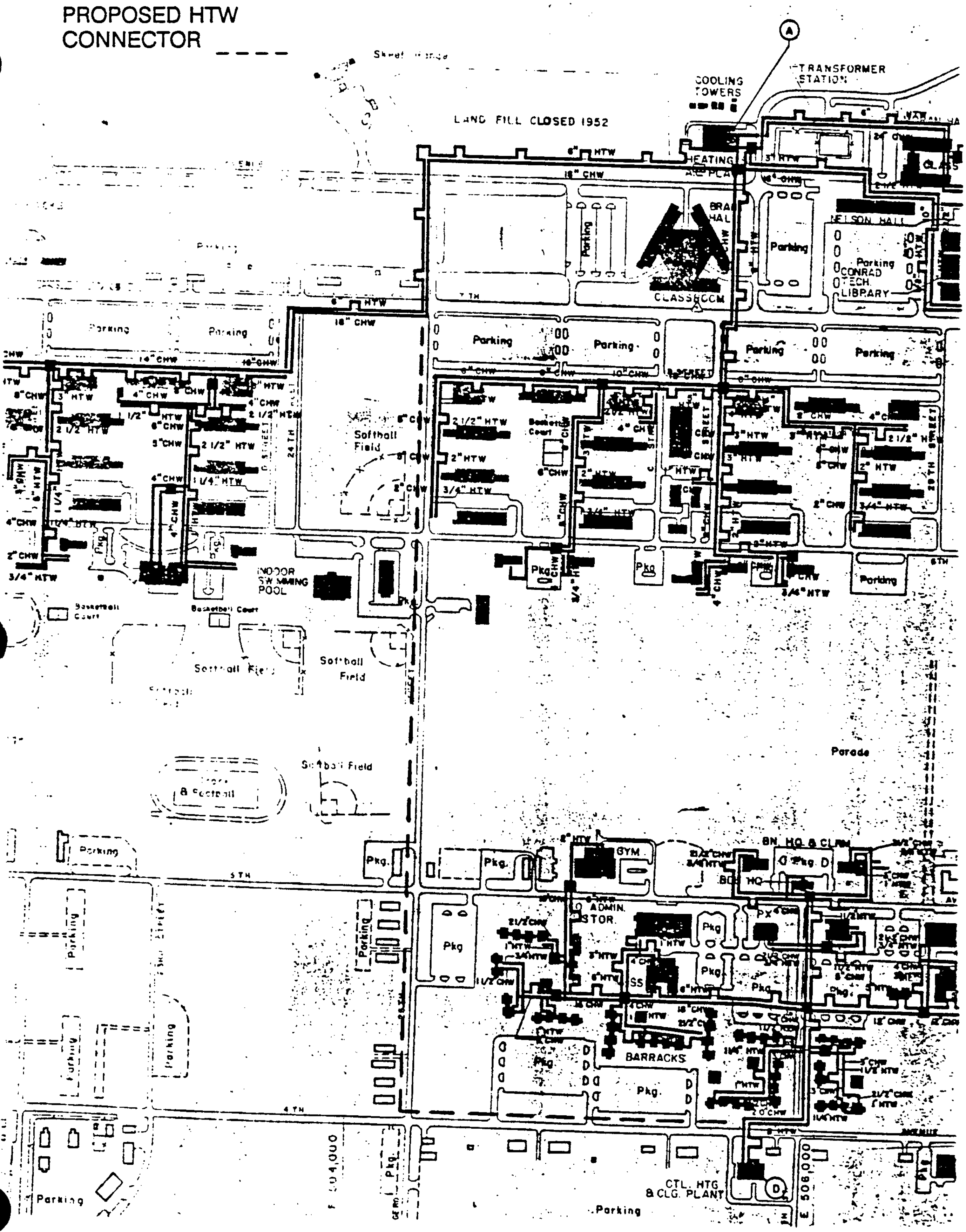

PROPOSED HTW
CONNECTOR
COOLING
TOWERS
TRANSFORMER
STATION
LAND FILL CLOSED 1952
HEATING
NELSON HALL
CONRAD
TECH
LIBRARY
CLASSROOM
Parking
Softball
Field
INDOOR
SWIMMING
POOL
Basketball Court
Softball Field
Parade
GYM
BN. HQ & CLRM
ADMIN.
STOR.
BARRACKS
Pkg.
CTL. HTG
& CLG. PLANT
E 504,000
E 506,000

FIGURE 1

5.0 PROJECT DEVELOPMENT

Several economically viable Energy Conservation Projects were evaluated for Fort Gordon's energy plants and are as follows:

<u>Building 25910 Energy Projects</u>

1. Variable Speed CHW Pumps

<u>Building 25330 Energy Projects</u>

1. Portable O_2 Analyzer
2. Variable Speed HTW Pumps
3. Variable Speed CHW Pumps
4. Use of Heavy Oil
5. Variable Speed Forced Draft Blowers

<u>Building 310 Energy Projects</u>

1. Variable Speed CHW Pumps
2. Variable Speed I.D. and F.D. Fans

None of the above projects meet the criteria for ECIP funding because the costs to implement are all under $200,000 threshold for that program. However, all of these projects have savings-to-investment ratios of 1.0 or greater and all should be considered for implementation under the QRIP or PECIP programs.

Regarding variable speed CHW and HTW pumping, it should be noted that insufficient and unreliable load profile information necessitated the use of alternative analysis methods. In the case of HTW pumping, fuel flow data was used to approximate the load and in the case of CHW pumping a generic case study was conducted. In both cases it appears that the projects are viable Energy Conservation Opportunities; however, without specific load data, an absolute determination cannot be made at this time. The lack of appropriate data precluded the assembly for a cost estimate and site specific energy savings information for the variable CHW pumping. As a result, a Life-Cycle Cost Summary could not be completed for this potential ECO.

In addition to the ECIP projects identified above, it is recommended that a number of O&M funded initiatives be instituted at the base level. Several of the O&M related projects offer substantial energy improvements and cost savings with a relatively small investment. Indeed, the QRIP/PECIP projects should not be undertaken until the higher priority O&M actions are implemented, or the cost savings potential of these projects will not be fully realized.

FORT GORDON PROJECT RECOMMENDATIONS

Project Descriptions	Project Type	Reference Report Sections
Boilers:		
Building 25330		
1. Replace Control System With Digital Controls & Recorders	O&M	3.2.1.1
2. Flame Safety System Service, Repairs & Operational Checks Required	O&M	3.2.1.2
3. Check Burner Nozzles for Wear & Correct Application	O&M	3.2.1.3
4. Clean & Service Forced Draft Fans	O&M	3.2.1.3
5. Repair/Replace O_2 Equipment		3.2.1.3, 4.4.1.1.4, 4.7
6. Service & Replace Gas Burners Defective Parts	O&M	3.2.1.3
7. Replace Oil Nozzles	O&M	3.2.1.3
8. Replace Gas Burner Rings	O&M	3.2.1.3
9. Set Combustion & Feedwater System to Maximum Capacity	O&M	3.2.1.4
10. Repair Feedwater Deaeration	O&M	3.2.1.6
11. Feedwater Treament Repair & Maintenance	O&M	3.2.1.7
12. Repair Distribution System Leaks	O&M	3.2.1.8
13. Regular Inspections for Boiler Refactory and Casing Repairs	O&M	3.2.1.9
14. Investigate Cause of Boiler #1 High Stack Temperatures	O&M	4.4.1.1.1
15. Monitor & Log Plant Performance	O&M	4.4.1.1.5
16. Develop Guide Worksheets & Train Operators in Appropriate Equipment Monitoring & Logging Procedures	O&M	4.4.1.1.5
17. Install Portable Combustion Gas Analyzer*	N/A	4.7.1
18. Install Variable Speed HTW Pumps*	QRIP	4.9.1.1

Project Descriptions	Project Type	Reference Report Sections
19. Inspect/Repair HTW Distribution System	O&M	4.11.1
20. Modify Plant to Allow Heavy Oil Use*	NA	4.14.1
21. Install Variable Speed F.D. Blowers*	NA	4.23.1
<u>Building 310</u>		
1. Test & Tune Combustion Contols on Regular Basis	O&M	3.2.2.1
2. Train Operators to Maintain Proper Control Operations	O&M	3.2.2.1
3. Check Flame Safety Limits & Adjust for Proper Operation	O&M	3.2.2.2
4. Develop Scheduled Testing Program to Maintain Ignition & Flame Safety System	O&M	3.2.2.2
5. Adjust Set Points for Gas/Air Mixture	O&M	3.2.2.3
6. Check/Replace Nozzles with Proper Sizes	O&M	3.2.2.3
7. Clean Burners	O&M	3.2.2.4
8. Set Controls to Recommended Maximum Burner Input	O&M	3.2.2.4
9. Adjust Boiler Set Points for Minimum Limits	O&M	3.2.2.5
10. Replace Feedwater Piping	O&M	3.2.2.6
11. Repair/Replace Feedwater Valve	O&M	3.2.2.6
12. Repair Deaerator & Boiler Feedwater System	O&M	3.2.2.6
13. Properly Operate Feedwater Preheat System	O&M	3.2.2.6
14. Service Boiler Ignition System	O&M	3.2.2.7
15. Check Steam Drum Level and Internal Steam Separator Baffles	O&M	3.2.2.8
16. Maintain O_2 Equipment for Efficienct Burner Operation	O&M	3.2.2.9

Project Descriptions	Project Type	Reference Report Sections
17. Check Burner Nozzles for Proper Sizing for #2 Oil	O&M	4.4.1.2.1
18. Calibrate Burner Controls	O&M	4.4.1.2.1
19. Insulate Atomizing Steam Lines	O&M	4.4.1.2.2
20. Monitor & Log Plant Performance	O&M	4.4.1.2.3
21. Develop Guide Worksheets & Train Operators in Appropriate Equipment Monitoring & Logging Procedures	O&M	4.4.1.2.3
22. Require Only One Boiler to 80% of Its Capacity Before Bringing a Second Boiler On Line	O&M	4.8.1.2
23. Inspect/Repair Distribution System	O&M	4.11.2
24. Variable Speed I.D./F.D. Fans*	NA	4.23.2
<u>Building 25910</u>		
1. Repair Feedwater Deaeration System	O&M	4.2.3

Project Descriptions	Project Type	Reference Report Sections
<u>Chillers</u>:		
1. Expand EMCS to Chiling Equipment in Two Phases	O&M	3.3.3
2. Develop Sequencing Plan	O&M	3.3.3
3. Review & Update O&M Department Guides	O&M	3.3.4
4. Re-Pipe Chiller Condensers to Cooling Towers	O&M	3.3.5
5. Repair/Replace Cooling Towers 1-3 and 5, 6 (Building 25910)	O&M	3.3.6.1
6. Replace/Repair Cooling Towers for Chillers 1 & 2 (Building 25330)	O&M	3.3.6.2
7. Log Chilled Water & Condensor Water Flow Rates on Plant Logs	O&M	3.3.7
8. Log Make-up Water Readings for Chilled Water System and Cooling Towers	O&M	3.3.7
9. Develop Refrigerant Conversion Program	O&M	3.3.8
10. Review Department Guides & Log Sheets for Proper Chiller Performance Monitoring Procedures	O&M	4.4.2.1
11. Develop Comprehensive Scheduled Calibration Program for all Plant Instrumentation & Measurement Equipment	O&M	4.4.2.2
12. Install Accurate Flow & Temperature Measuring Instrumentation & Record Both	O&M	4.8.2
13. Install Variable Speed Pumping $*_1$	NA	4.9.2
14. Sequence Chillers in Following Manner: Chiller 2, 3, 4B & 4A for Efficiency (Building 25910)	O&M	4.13.1
15. Operate Chillers 1 & 2 at 80% or Above (Building 25330)	O&M	4.13.2

* See Life-Cycle Cost Analysis Summaries for Further Review
$*_1$ Further Review Recommended -- Generic Study

PRODUCTIVITY CAPITAL INVESTMENT PROGRAM

Project	Cost	Annual Savings ($)	S/I	Amortization (YR)	Program
Add O_2 Analyzer, Bldg. 25330	$ 2,000	$ 2,535	N/A	0.8	N/A
Variable Speed HTHW Pumps, Bldg. 25330	51,000	25,969	4.7	2.0	QRIP
Modifications To Allow Heavy Oil Use, Bldg. 25330	75,000	6,367	1.0	11.8	N/A
Variable Speed Forced Draft Blowers, Bldg. 25330	20,000	3,590	1.6	5.6	N/A
Variable Speed I.D./F.D. Fans, Bldg. 310	27,000	4,789	1.6	5.6	N/A

DOCUMENTATION FOR PRODUCTIVITY CAPITAL INVESTMENT PROGRAMS For use of this form, see AR 5-4; the proponent agency is OCA.	1. PROJECT NO.	REQUIREMENT CONTROL SYMBOL DD-M(R) 1561	
2. TO: / 3. THRU:	4. FROM:	5. DOD COMP NAME	6. DOD COMP CODE
		7. COMMAND CODE	8. DATE

9. PROJECT TITLE	10. TYPE OF PROJECT (Check one)	11. AMORTIZATION YEARS/MONTHS
Variable Speed HTHW Pumps, Bldg. 25330	[X] GRIP [ ] OSD PIF [ ] PECIP	$ 51,000 (Project Cost) ÷ 25,969 (Average Annual Savings) X 12 (No. Mos) = 2.0 (years) or ____ (months) (amortization)

12. FUNCTIONAL AREA WHERE SAVINGS WILL OCCUR	13. ECONOMIC LIFE	14. EXPECTED OPERATIONAL DATE
024 Army Energy Management	15 years	June 1992

15. SUBMITTING UNIT(S)	16. UNIT ID CODE	17. PROJECT DESCRIPTION
		Equip the two 100HP HTHW Zone Pumps in Bldg. 25330 with adjustable frequency variable torque AC drives and associated controls/interfaces to reduce electrical consumption associated with HTHW pumping.

18. DETAILED JUSTIFICATION

Analysis of load information developed from fuel use data for this plant indicates that the pumps would be operated at much less than rated capacity for most of the year. The horsepower input to the pumps varies as the cube of the volumetric flow rate increase (or decrease) from the pump. Consequently, even small decreases in pump flow can result in substantial power savings. These pumps are sized to the plant capacity which is substantially in excess of the load serviced. Consequently, the pumps are capable of pumping at much higher rates than necessary during normal operations. By installing variable frequency variable torque motor drives, the pump speed (and consequently the

(see attach sheet)

19. SAVINGS DISPOSITION

20. OTHER REMARKS (Continue on page 5, if more space is needed)

DA FORM 5108-R, MAY 82

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R).

pump output) can be reduced at low load demand resulting in significant savings.

21a.

SUMMARY OF DOLLAR SAVINGS
(ROUND OFF TO THE NEAREST DOLLAR)

Attach computation sheet identifying the method and source of data for savings

SAVINGS BREAKOUT	PRESENT METHOD	PROPOSED METHOD				DIFFERENCE/SAVINGS			
		1ST YR	2D YR	3D YR	4TH YR	1ST YR	2D YR	3D YR	4TH YR
SALARY/LABOR/ OVERTIME									
MATERIAL/ SUPPLIES									
UTILITIES									
MAINTENANCE/ REPAIR									
TRANSPORTATION									
LEASE COSTS									
SALVAGE/ TURN-IN									
ENERGY *(Identify)* Elec.	27,944	1975				25,969			
CONTRACT COSTS									
OTHER *(Identify)*									
TOTALS									

b. **PRIORITIZATION**

(1) **INTERNAL RATE OF RETURN *(IRR)***

Divide estimated project cost 51,000 by average annual savings 25,969 = 2.0 factor.

Based on factor and number of years economic life of the project, select the IRR from Table H-3, App H, Ch. 5, AR 5-4 = 65 % IRR.

(2) **SAVINGS TO INVESTMENT RATIO *(S/I)***

Multiply annual savings 25,969 X discount factor 9.19 = 238,655 and divide by present value of investment *(undiscounted)* 51,000 = 4.7 S/I.

(Based on economic life 15 years, select discount factor from Table H-4, App H, Ch. 5, AR 5-4.

(3) **RATE OF INVESTMENT PER MANPOWER SPACE *(RIMS)***

Divide estimated project cost ______ by number of manpower space savings ______ = ______ RIMS.

(Manpower requivalents cannot be used in this computation.)

22. COST FOR PROJECT TO BECOME OPERATIONAL

EQUIPMENT TYPE a	PROPOSED SOURCE OF PROCUREMENT b	UNIT PRICE c	QUANTITY d	TOTAL COST e	APPROPRIATION, BUDGET ACTIVITY OR PROGRAM ELEMENT f	FY FUNDS REQUIRED g
(1)						
(2)						
(3)						
(4)						
(5)						
(6) TRANSPORTATION (Equipment delivery)						
(7) EQUIPMENT MODIFICATION[1]						
(8) EQUIPMENT INSTALLATION				51,000		
(9) MAINTENANCE CONTRACT[2]						
(10) FACILITIES MODIFICATION[3]						
(11) TRAINING						
(12) OTHER (Specify):				-0-		
(13) TOTAL REQUIRED FOR PROJECT TO BECOME OPERATIONAL[4]				51,000		
(14) TOTAL AMOUNT OF FUNDING REQUESTED IN THIS PROPOSAL				51,000		
(15) TOTAL AMOUNT OF FUNDING REQUIRED FROM OTHER SOURCE[5]				-0-		
(16) TOTAL (Sum of (14) + (15) above)				51,000		

[1] *Not to exceed 10% of equipment cost for QRIP projects.*

[2] *Applicable to OPA QRIP provided cost is included in packaged deal involving one bill for the equipment and initial maintenance.*

[3] *Normally not OPA funded.*

[4] *Used to compute amortization in Item 11.*

[5] *Specify source to include certification that funds are available, if financed from the regular budget:*

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Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

23. SUMMARY OF SAVINGS (*MANPOWER AND DOLLARS*)

ITEMS	SAVINGS			REAPPLICATION OF SAVINGS					
	NO. MPR OR MHR	TYPE PERS[6]	DOLLARS	PROGRAM ELEMENT		TDA PARA AND LINE		FUNCTION CODE	
a	b	c	d	e. FROM	f. TO	g. FROM	h. TO	i. FROM	j. TO
(1) REQUIREMENTS AND AUTHORIZATIONS ELIMINATED									
(2) REQUIREMENTS ONLY ELIMINATED									
(3) BORROWED MILITARY MANPOWER RELEASED									
(4) OVERHIRES OR TEMPORARIES TERMINATED									
(5) HOURS OVERTIME ELIMINATED									
(6) MANHOURS SAVED FROM MULTIPLE POSITIONS[7]									
(7) OTHER DOLLAR SAVINGS (*Excluding Manpower*), e.g., CONTRACT COSTS & UTILITIES									
(8)									
(9)									
(10)									
(11) TOTAL DOLLAR SAVINGS									

6 *(1) US Graded*
(2) US Wage Board
(3) DHFN
(4) IHFN
(5) Officer
(6) WO
(7) Enlisted

7 *Reflect specific duties being performed with additional manhours available (equivalent manyears)*

24. REGULATORY APPROVAL/COORDINATION

a. INVESTMENT STATEMENT

This proposal has been reviewed and it cannot be implemented with existing equipment or facilities. This investment is in accordance with established investment planning. The project complies with public laws, OSD policies and regulations, and all other regulatory constraints.

____

(Cite regulatory approvals, e.g., TAGO Control No.) (Ex. New Start, TAGO Approval, etc.)

b. OTHER COORDINATION *(Functional Coordination at local level, e.g., Fac Eng, Log, Pers, etc.)*

____

____

25. SUBMITTED BY *(Typed name, grade and title of Subordinate Command/Agency or Project Initiator)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
26. APPROVAL RECOMMENDED BY *(MACOM/Agency)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
FOR USE BY HQDA ON OSD PIF PROJECTS ONLY		
27. APPROVED BY	SIGNATURE	DATE *(YYMMDD)* AUTOVON

20. OTHER REMARKS *(Cont'd)*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: FT GORDON REGION NO.____ PROJECT NUMBER ____________

PROJECT TITLE VARIABLE SPEED HTHW PUMPS FISCAL YEAR ____________

DISCRETE PORTION NAME BLDG 25330

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 51,000
   B. SIOH $ 2805
   C. DESIGN COST $ 3060
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 51179
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $ —
   F. TOTAL INVESTMENT (1D-1E) $ 51179

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$ 25969	9.19	$ 238,655
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 25969		$ 238,655

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ —
      (1) DISCOUNT FACTOR (TABLE 1) ______
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ —

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.____	$			$
b.____	$			$
c.____	$			$
d. TOTAL	$			$

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ —

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 78756
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 25969

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 238655

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 4.7

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: FT GORDON REGION NO. ___ PROJECT NUMBER ___

PROJECT TITLE USE of #6 OIL FISCAL YEAR ___

DISCRETE PORTION NAME BLDG 25330

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 74,850
   B. SIOH $ 4117
   C. DESIGN COST $ 4491
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 75112
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $
   F. TOTAL INVESTMENT (1D-1E) $ 75112

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$ 6367	13.25	$ 84363
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 6367		$ 84363

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ -1000
      (1) DISCOUNT FACTOR (TABLE 1) 9.11
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -9110

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -9110

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 27840
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ___
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 5367

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 75253

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= $\frac{75253}{75112} = 1.0$

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft Gordon REGION NO.____ PROJECT NUMBER________

PROJECT TITLE Variable Speed FD Blowers FISCAL YEAR________

DISCRETE PORTION NAME Bldg 25330

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY Kr

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 20,000
   B. SIOH $ 1100
   C. DESIGN COST $ 1200
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 20,070
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $ —
   F. TOTAL INVESTMENT (1D-1E) $ 20,070

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$ 3590	9.19	$ 32,992
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 3590		$ 32,992

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ —
      (1) DISCOUNT FACTOR (TABLE 1) ____
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ —

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $____

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 10887
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ____
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 3590

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 32992

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 1.6

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft Gordon REGION NO. ___ PROJECT NUMBER ___

PROJECT TITLE Variable SPD FD/ID Fans FISCAL YEAR ___

DISCRETE PORTION NAME Bldg 310

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY RD

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 27,000
   - B. SIOH $ 1,485
   - C. DESIGN COST $ 1,620
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ —
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $ ___
   - F. TOTAL INVESTMENT (1D-1E) $ 27095

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$ 4789	9.19	$ 44011
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 4789		$ 44011

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ —
     - (1) DISCOUNT FACTOR (TABLE 1)
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) ___ $ —
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ ___
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 14524
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ___
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 4789

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ ___

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 1.6

LIFE-CYCLE COST ANALYSIS

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: FT GORDON REGION NO.____ PROJECT NUMBER____________

PROJECT TITLE VARIABLE SPD FD/ID FANS FISCAL YEAR____________

DISCRETE PORTION NAME BLDG 310

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 27,000
   B. SIOH $ 1485
   C. DESIGN COST $ 1620
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ —
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $____
   F. TOTAL INVESTMENT (1D-1E) $ 27095

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$ 4789	9.19	$ 44011
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 4789		$ 44011

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ —
      (1) DISCOUNT FACTOR (TABLE 1)
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ —

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $____

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 14524
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ____
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 4789

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $____

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 1.6

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft Gordon REGION NO.____ PROJECT NUMBER________

PROJECT TITLE USE of # 6 OIL FISCAL YEAR________

DISCRETE PORTION NAME BLDG 310

ANALYSIS DATE 3/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 74850
   - B. SIOH $ 4117
   - C. DESIGN COST $ 4491
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 75112
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $
   - F. TOTAL INVESTMENT (1D-1E) $ 75112

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$ 4157	13.25	$ 55080
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 4157		$ 55080

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ -1000
     - (1) DISCOUNT FACTOR (TABLE 1) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ - 9110
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.____	$			$
b.____	$			$
c.____	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -9110
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 18176
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ________
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 3157

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 45970

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= $\frac{45970}{75112} = 0.6$

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION: FT. GORDON REGION NO. 4 PROJECT NUMBER ______

PROJECT TITLE STUDY BLDG 310 FISCAL YEAR ______

DISCRETE PORTION NAME BLOW DOWN HT. EXCHANGER #2 WASTE HEAT

ANALYSIS DATE 12/88 ECONOMIC LIFE 15 YEARS PREPARED BY D. SMITH

1. INVESTMENT
   - A. CONSTRUCTION COST $27,231
   - B. SIOH 5.5% $1,498
   - C. DESIGN COST 6.0% $1,634
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $27,326
   - E. SALVAGE VALUE -$0
   - F. TOTAL INVESTMENT (1D-1E) $27326

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST & DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)*	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3) (1x2)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5) (3x4)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$4.95	563.87	$2788.61	14.32	$39933
E. COAL	$		$		$
F. TOTAL		563.87	$2789.61		→ $39933

3. NONENERGY SAVINGS(+) / COST(-)
   - A. ANNUAL RECURRING (+/-) $-250 1 day maint./yr x 250
     - (1) DISCOUNT FACTOR (TABLE A) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $2278
   - B. NONRECURRING SAVINGS(+) / COST(-)

ITEM	SAVINGS(+) COST(-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR(3)	DISCOUNTED SAVINGS(+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$ 0

   - C. TOTAL NONENERGY DISCOUNTED SAVINGS(+) / COST(-) (3A2+3Bd4) $-2278
   - D. PROJECT NONENERGY QUALIFICATION TEST
     - (1) 25% MAX NONENERGY CALC (2F5 X .33) $13,178
       - a IF 3D1 IS = OR > 3c GO TO ITEM 4
       - b IF 3D1 IS < 3C CALC SIR = (2F5+3D1)÷1F= ______
       - c IF 3D1b IS = > 1 GO TO ITEM 4
       - d IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d÷YEARS ECONOMIC LIFE) $2539

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $37655

6. DISCOUNTED SAVINGS RATIO (IF < 1 PROJECT DOES NOT QUALIFY)
   (SIR)=(5÷1F) = 1.38

*M = MEGA = 10^6